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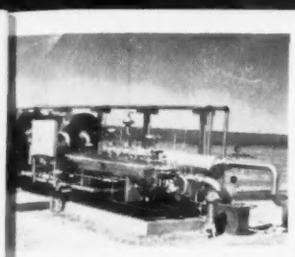
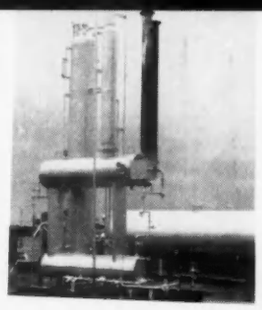

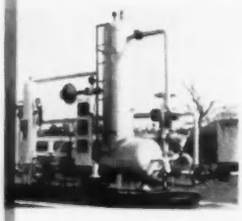
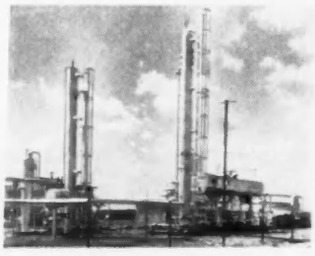
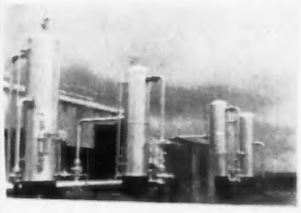
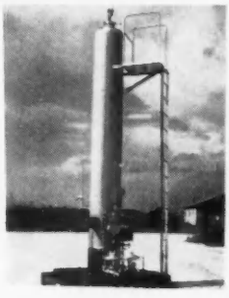

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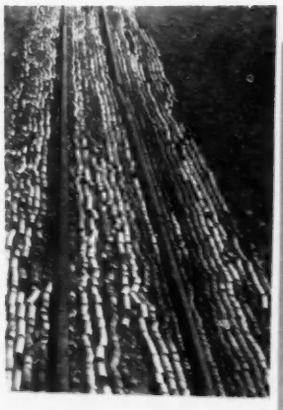

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OIL INDUSTRY IN BRIEF

Here are the latest industry trends, revealed by WORLD OIL and industry research:

On the plus side

Petroleum demand improves. Demand for all oils averaged 10.2 million barrels daily in November, up 1¼ million barrels daily over October, and 897,000 barrels daily or 9.6 percent higher than November 1958 . . . See Page 25.

Oversupply decreases. Previously bothersome surpluses of products have been cut sharply. Prospects are that industry will start new year with crude oil stocks and principal refined products at economically desirable levels . . . See Page 25.

Prices stable. Product prices have been holding up well in most areas. Some weakening of gasoline prices have been balanced by moderate increases in heating oil prices . . . See Page 25.

Equipment sales increase. Purchases of oilfield equipment and machinery increased about 16 percent to $930 million in 1959 . . . See Page 13.

Gas wildcatting up. Gas and condensate wildcats were the only phases of drilling activity showing increases during first 11 months of 1959, with gas wildcat total up 26 percent to 257 wells . . . See Page 29.

On the minus side

Rig totals decrease. 4,178 rigs were operating on October 31, down 232 rigs or 5.3 percent from same date in 1958 . . . See Page 29.

Daily completions down. New well completions averaged 126 per day in November, down 9.7 percent from 136 per day average in October and also in November 1958 . . . See Page 29.

Footage decreases. Footage drilled averaged 510,000 feet per day in November, down 10 percent from October and 3.8 percent from November 1958 . . . See Page 29.

Natural gas issue confused. Government says industry should initiate new natural gas bill, industry says government should. This stalemate and other factors may delay passing of workable measure . . . See Page 17.

a Quick Look at this issue . . .

BUSY OIL MEN: To help you put first things first, scan these time-saving digests on this and the following pages, checking ☑ those you want to read first.

PRODUCTION PRACTICES MANUAL

☐ **The oil and gas separator** . . . The conventional separator is widely used in the field and is considered a basic item of producing equipment for both oil and gas wells. Some types of gas wells are produced exclusively through separators and almost all type of gas well producing equipment (dehydrates, H-C recovery units, etc.) utilize separators within their systems to some extent. Because conventional units must be selected with care for proper results, Part 1 of the Production Practices Manual is devoted to this subject. This initial installment discusses conventional separation in detail, including advantages and disadvantages of the various type of vessels and correct methods for selecting the proper unit for a particular application. . . . **Page 84**

☐ **The low temperature separation unit** . . . The low temperature unit (LTS) is widely used in the production of natural gas wells when a pressure drop between wellstream flowing pressure and sales line pressure of approximately 1,000 psi is available. Basically the mechanical low temperature unit consists of a low temperature separator, free liquid knockout, heat exchanger and choke. A flash or second stage separator also can be used to advantage in most cases. This section of the Production Practices Manual discusses each of the component parts of the low temperature unit, the various types of low temperature separators, use of LTS units with accessory equipment (stabilizers, steam generators, glycol injection systems), piping and hook-ups and some operating techniques. . . . . **Page 93**

☐ **The long cycle dry desiccant dehydrator** . . . Dry desiccant dehydration is an accepted, proven method of drying natural gas in the field. Adsorbers now in use, all of which do an excellent job, range from the vertical downflow type to the compartmented horizontal type. Because of conservative design which allows 8-hour heating and cooling cycles, the long cycle unit will provide very low dewpoints, particularly in cold weather areas where extreme dependability is a necessity. New desiccants, better equipment and automation have stimu-

lated interest and increased acceptance of the technique ..... Page 100

☐ **The calcium chloride gas dehydrator** . . . Calcium chloride gas dehydration units use a solid chemical bed for dehydration of natural gas. A series of self-circulating trays are used to handle brine formed in the unit. These units operate efficiently over a wide range of flow rates, pressures and temperatures. The dehydrator has no moving parts, requires no regenerative heater or process pump and will operate unattended for long periods of time. Because natural gas contains no free oxygen, interior corrosion has not been a problem. $CaCl_2$ units now are being used to process gas containing as much as 60 percent hydrogen sulfide. For a complete discussion of the $CaCl_2$ unit, see..... Page 105

☐ **How major geologic features developed in Kansas** . . . Deposition and erosion cycles during Paleozoic times combined with gentle regional structural movements throughout the post-Cambrian provide the key to understanding the origin of the state's widespread oil and gas fields for guiding exploration for new deposits. A concise and thoroughly illustrated article is given by one of the foremost authorities on Kansas geology Page 119

New drilling method described

SUCCESSFUL FIELD tests of a new reverse circulation method reveal the following advantages:

Earl

- Provides accurate evaluation of the entire lithological interval, thus aiding the search for stratigraphic traps and other structural phenomena
- Reduces hydraulic surface requirements
- Minimizes lost circulation conditions
- Minimizes crooked hole problems.

The core is broken off in sections 2 inches in diameter and 6 inches long as it passes through a bottom-hole core breaker. The sections, along with the cuttings, are transmitted to the surface through the core tube. The drilling medium (air or fluid) is circulated down through the tubular annulus and returns through the core tube.

Equipment used includes a highly portable rig, dual drill pipe and an electric swivel.

For the first detailed description of the new method to be published, including authoritative comments on its potential, turn to **Page 111.**

Jack F. Earl

☐ **Drilling costs reduced with aerated seawater.** Aerated seawater used on a recent Bahama California Company's Florida Key well has proven successful while drilling through the lost circulation zones normally encountered in this area. Although the quality of the ditch samples and electrical logs was reduced while using this medium of circulation, over-all drilling costs were reduced. For a complete discussion of the results and practices while using aerated seawater, turn to **Page 125**

☐ **Here's how to improve your gas lift installations (Part 6)** . . . Gas lift valve specifications and force balance equations can be used to great advantage in solving many G/L installation design problems. However, the importance of such data often is overlooked by many operators. It should be remembered that simplified charts and equations do not necessarily provide the most efficient design possible. Calculations presented in this article for determining the operating valve, for estimating fall-back and for design of gas lift installations (five problem examples) require application of specifications and force balance equations. For complete and previously unpublished information on this phase of gas lift, turn to..... Page 129

☐ **What's ahead for South Texas' deep Edwards trend?...** A WORLD OIL survey of major operators reveals that deep Edwards wildcatting activity is expected to gain momentum in 1960—if certain critical wells become good producers. The same is true for the Lower Wilcox and the new Lower Frio trends. For a timely, informative study of South Texas' deep drilling potential, including description and location of the critical wells, discussion of the geology, drilling and production in the area's two key fields, Person and Fashing—plus a history of the significant deep Edwards discoveries in recent years, turn to..... Page 136.

☐ **Portable core analysis lab saves offshore rig time** . . . Packaging a complete core analysis laboratory in five suitcase-size boxes that can be set up on offshore or remote inland locations is enabling certain California offshore operators to make substantial savings in reduced rig downtime. For a quick evaluation of this specially designed equipment, how it is used, plus some typical examples of savings to be realized, turn to..... Page 145

Most accurate industry forecast

WHAT DOES 1960 hold for the petroleum industry? For your company?

No one knows, for certain.

But surveys and intelligent forecasting provide some excellent clues to probable business developments. According to the often-used phrase, accurate forecasts can "show the way to promotion and pay."

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thoritative estimates of the volume of business in store for the oil and gas industries, information on market trends and prospects, and forecasts of the various activities to be carried out by oil and gas companies in the year ahead.

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The 42nd annual Forecast-Review Issue of WORLD OIL will be published February 15, 1960. It will contain the many important and useful features of the past, such as the drilling and petroleum consumption forecasts.

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- Progress report on new drilling methods and equipment.
- Latest developments in production practices and equipment.

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PETROLEUM REFINER and The REFINERY CATALOG for the oil, gas and petrochemical processing industry.

Indexed by Industrial Arts Index and Engineering Index

Looking Ahead

'60 economic outlook: promising . . . Cautious optimism prevails for oil industry economics, with caution centering on production and refinery runs to make sure 1959 oversupply problems will not repeat this year.

Indiana Standard Board Chairman Frank O. Prior says product demand will increase 3.1 percent during first six months—capital outlays will come within shooting distance of $5.2 billion spent in the U.S. last year. More money will be spent for modernization, less for capacity increases.

Business and Defense Services Administration estimated 1959 factory shipments of oil field, gas and water well drilling equipment was up 16 percent to $930 million in 1959—predicted drilling activity, along with machinery and equipment purchases, to be up about 3 percent in 1960.

Looking ahead in Washington . . . Same old crazy quilt of probes, bills and increasing bureaucratic control will prevail in 1960 . . . **Little action expected** on natural gas bill without full Administration support . . . **House Ways and Means Committee Chairman Wilbur Mills predicts** little or nothing will be done this year to change oil and gas depletion provision, says he is convinced there is positive need for the provision as recovery against capital loss . . . **Although Ways and Means Committee decided against such action,** President Eisenhower is expected to urge new two-stage gasoline tax boost in 1960 budget request to Congress; new proposal would hike tax 2 cents, as opposed to original Administration recommendation for 1½-cent increase over a five-year period . . . **There will be one new twist:** Bureau of Mines is expected to start intensive survey of oil exploration and development costs early this year, the first such study to be conducted. Questionnaire, simplified considerably from original, will probe deeply into economic history of thousands of producers.

Promising exploration areas opening up . . . Several critical wells are being completed that may hold key to new surge of deep drilling (below 10,000 feet) in South Texas' Lower Edwards, Wilcox and Frio trends (See Page 136).

Recent discoveries north of Aneth (Pennsylvanian) productive area enhance Mississippian, Devonian and possible Cambrian oil and gas potential in Four Corners area. Test recently completed by Pure Oil on flank of major salt fold in Utah found more than 400 feet of porous Mississippian carbonate section, saturated with gas and condensate.

In mid-December, Shell Oil and Northern Pacific Railway completed discovery that may open up a new Williston Basin area. The McKenzie County well flowed a potential of 1,526 barrels of oil daily through a 32/64-inch choke from two perforations at 9,399 feet, in the Mississippian. Well is 35 miles south of current production at south end of Nesson Anticline in a comparatively undrilled part of the basin.

How about gas-created electricity at the wellhead? . . . Production model of electric generator that can be mounted on gas well flow lines to supply 1,100 watts of AC power at 114 volts is now undergoing what is hoped to be the final test.

None of the gas is allowed to escape. Small differential across a pneumatic turbine is sufficient to drive the generator. Unit is enclosed in compact case pressure tested to 10,000 psi, has interchangeable parts.

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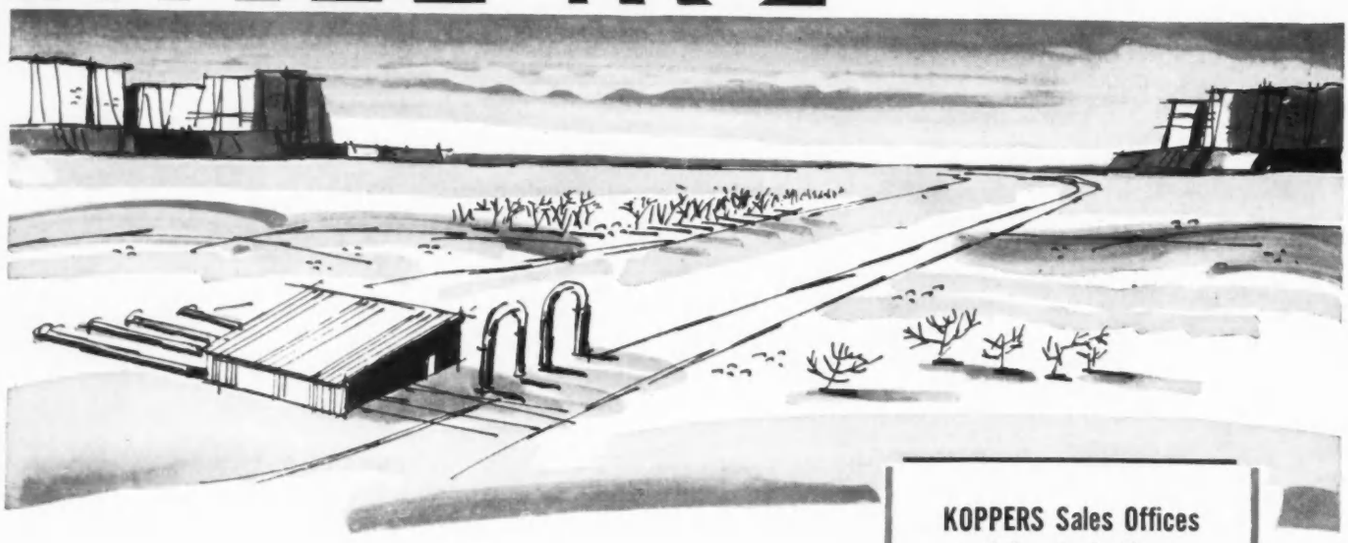

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Further delay is dangerous

AFTER NEARLY 5½ YEARS, two natural gas bills and two presidential vetoes, efforts to clarify federal regulation of natural gas producers appears to be more muddled than ever. Following is the current confused state of affairs in brief:

- Oil industry leaders, Senate Majority Leader Lyndon Johnson and the creator of two natural gas bills, Orin Harris, have publicly stated that no action is expected unless the Administration makes some strong recommendations and then gives them strong support.
- Taking the other tack, Interior Secretary Fred Seaton has urged the industry to take the lead in initiating a bill that would both simplify federal regulations and provide ample protection for consumers. He refused to commit the Administration to any direct action on a new natural gas bill.

While the traditional, progress-curbing see-saw of political inaction runs its multi-year course, the Federal Power Commission continues to reel under a staggering backlog of rate cases—natural gas drilling efforts are slackening—the rate of additions to proved reserves is slowing down—more and more producers are selling gas under intra-state contracts to avoid the stifling red tape of federal control.

As a result, the entire nation is suffering. Thousands of potential consumers are left dangling on the waiting list to receive a cheap, clean, highly efficient fuel.

It is high time that natural gas be taken out of the "political football" class. And there could be no better time than 1960.

Several factors favor such action. The Administration has indicated it is vitally interested in straightening out the natural gas mess. Also, an increasing number of natural gas distributors are easing up on their opposition to reduced producer controls.

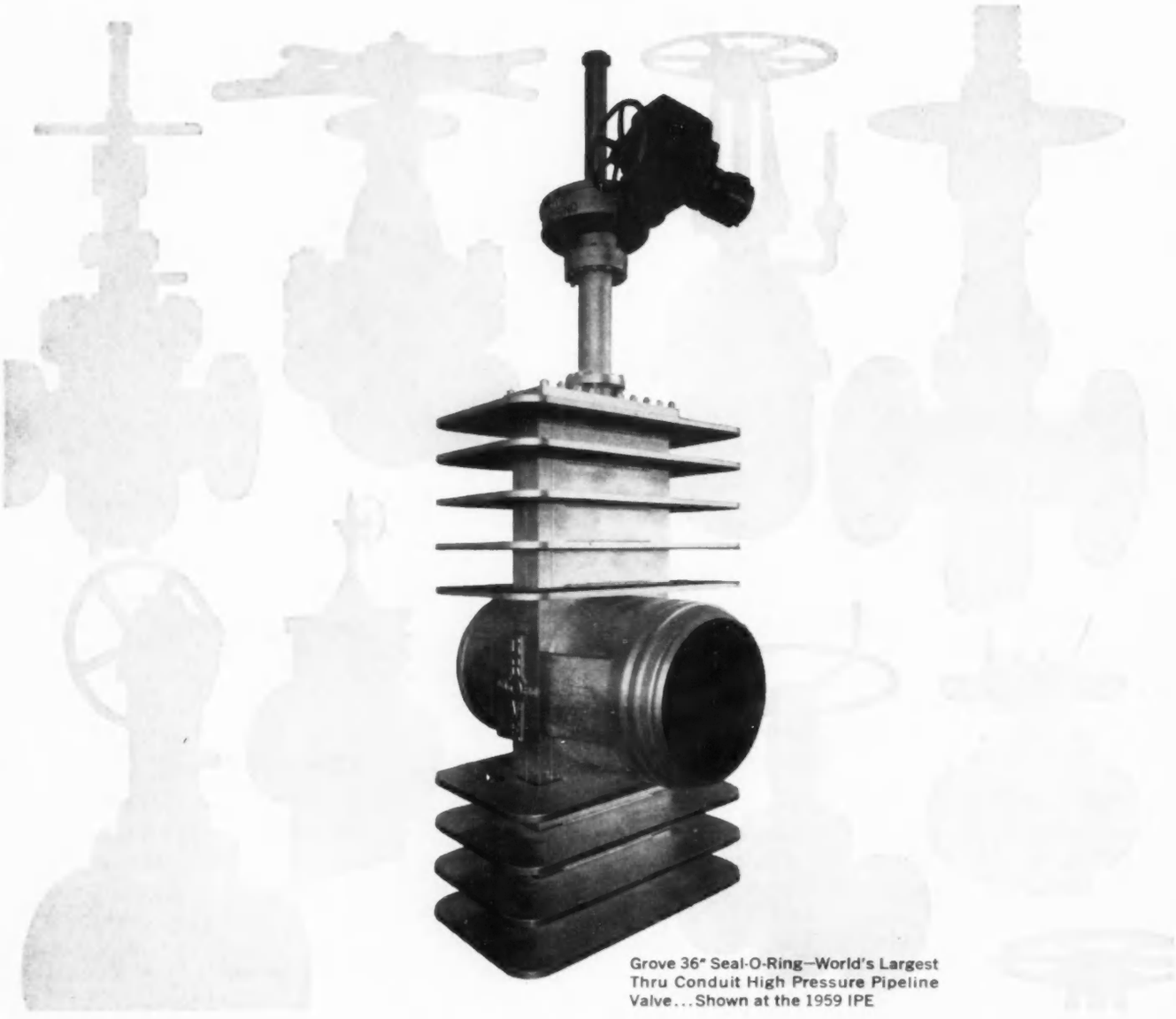
But there still remains one powerful group whose efforts to tighten federal control continue unabated. They are the city and state officials.

Even so, the path can be cleared to workable legislation in the near future—if statesmanship and responsibility are executed on three fronts:

1. Industry and government must drop their "let the other guy do it" attitude. And, after two vetoes, the scales lean heavily toward the Administration taking the initiative.
2. Intra-industry haggling must stop. Producers, transmission companies and distributors must join together in a common front.
3. City and state officials must be made to realize that the nation's welfare transcends individual interests.

These are the prerequisites. Adopt them and the nation's economy takes a giant stride forward. Ignore them and a vital industry continues indefinitely to wallow in the mire of political inaction.

Which will it be?



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Strong demand using up oil surpluses

THE INDUSTRY'S economic situation improved greatly in November, and further betterment was in prospect for December. Demand for petroleum has been remarkably strong. Supplies have been held within reasonable bounds. Previously bothersome surpluses of products have been largely eliminated. Prospects are good that the industry will start off the new year with stocks of crude and principal products at economically desirable levels.

Markets have been fairly stable for several months. Crude prices are holding generally, following some recent reductions for certain grades and areas. Product prices also have been stable, showing no material change in the aggregate. Some weakening of gasoline prices has been compensated by moderate increases in prices of heating oils.

Demand up sharply. Total demand for all oils in November was remarkably high. Averaging 10,199,000 barrels daily, it was 1¼ million barrels a day greater than in October and 897,000 barrels daily or 9.6 percent greater than in November 1958, setting a new all time record for November. With exports lower than a year ago, domestic consumption was up even more sharply, running almost 1 million barrels a day or 10.8 percent above November 1958.

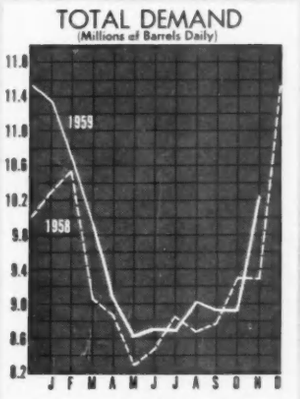
The exceptionally strong demand for petroleum in November reflected two major causes. They were abnormally cold weather and stimulation of business activity by termination of the long steel strike. Demand for heating oil was very great. Residual fuel oil was in strong demand. Gasoline demand also showed a good year to year increase.

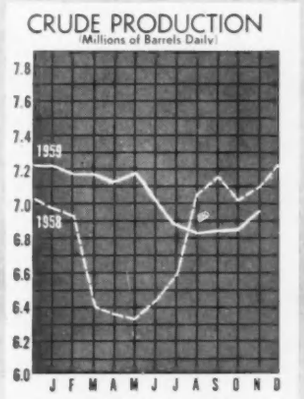
Distillate fuel oil demand in November averaged 2,362,000 barrels daily, almost 400,000 barrels or 20 percent more than in November 1958. It was the heaviest November demand in history.

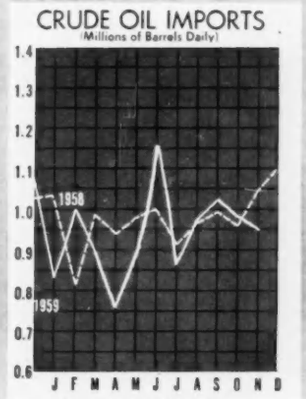
Kerosine demand averaged almost 400,000 barrels daily, up about 50,000 daily or 15 percent over November 1958.

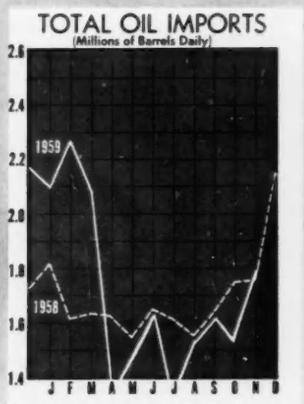
Residual fuel oil demand of 1,678,-

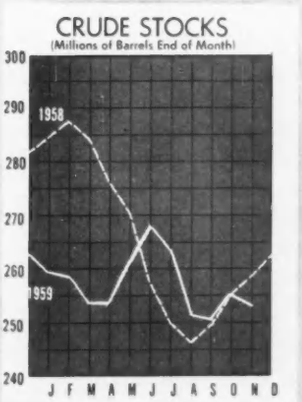
Petroleum Trends...

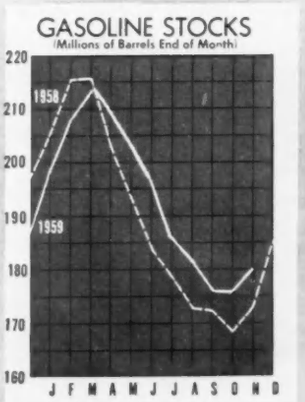


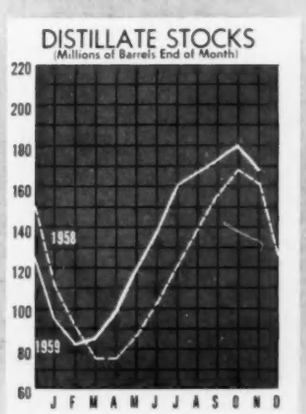


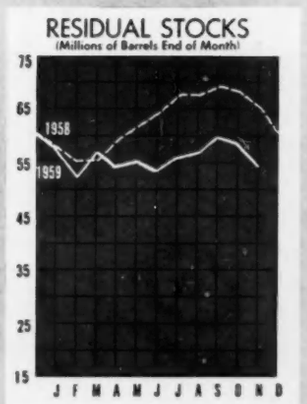












U.S. Petroleum Demand and Supply (Thous. Bbls. Daily)

ITEM	NOVEMBER 1959	NOVEMBER 1958	% Diff.	Oct. 1959	JANUARY-NOVEMBER 1959	JANUARY-NOVEMBER 1958	% Diff.
DEMAND							
All Oils, Total Demand	10,199	9,302	+ 9.6	8,913	9,550	9,138	+ 4.5
Domestic Demand	9,969	8,996	+10.8	8,678	9,308	8,858	+ 5.1
Export Demand	230	305	—24.6	235	243	281	—13.5
Gasoline, Total Demand	3,941	3,775	+ 4.4	4,010	4,125	3,961	+ 4.1
Distillate, Total Demand	2,362	1,968	+20.0	1,506	1,779	1,716	+ 3.7
Kerosine, Total Demand	399	346	+15.3	270	286	290	— 1.4
Residual, Total Demand	1,678	1,555	+ 7.9	1,491	1,584	1,476	+ 7.3
Other Oils, Total Demand	1,819	1,658	+ 9.7	1,636	1,776	1,695	+ 4.8
CHANGE IN STOCKS							
All Oil, Change in Stocks	—573	+282	.....	+368	+112	—26	.....
NEW SUPPLY							
Total New Supply	9,626	9,584	+ 0.4	9,281	9,662	9,113	+ 6.0
Domestic Production, Total	7,835	7,826	+ 0.1	7,715	7,900	7,460	+ 5.9
Crude Oil	6,935	6,984	— 0.7	6,855	7,031	6,670	+ 5.4
Natural Gas Liquids	900	842	+ 6.9	860	869	790	+10.0
Imports, Total	1,791	1,758	+ 1.9	1,566	1,762	1,653	+ 6.6
Refined Products	841	791	+ 6.3	568	803	711	+12.9
Crude Oil, Total	950	967	— 1.8	998	958	942	+ 1.7
Crude, East Coast	693	767	— 9.6	733	730	763	— 4.3
CRUDE RUNS							
Crude Runs to Stills	7,917	7,776	+ 1.8	7,667	7,975	7,573	+ 5.3
Domestic Crude	6,901	6,787	+ 1.7	6,665	7,016	6,636	+ 5.7
Foreign Crude	1,016	989	+ 2.7	1,002	959	936	+ 2.5

U.S. Stocks of Oils (Million Bbls. at End of Month)

KIND OF OIL	TOTAL IN U.S. Nov. 1959	TOTAL IN U.S. Nov. 1958	% Diff.	Oct. 1959	EAST OF CALIFORNIA Nov. 1959	EAST OF CALIFORNIA Nov. 1958	% Diff.	Oct. 1959
All Oils	828.4	831.3	— 0.3	845.6	.....	.....	.....	.....
Crude Oil	252.6	257.5	— 1.9	256.3	219.3	219.1	+ 0.1	223.9
Gasoline	180.4	178.6	+ 1.0	176.0	153.8	154.7	— 0.6	150.9
Distillate Fuel Oil	165.9	161.2	+ 2.9	181.6	153.2	147.7	+ 3.7	166.2
Kerosine	30.9	32.1	— 3.7	33.0	30.5	31.8	— 4.1	32.6
Residual Fuel	54.9	66.2	—17.1	58.0	30.3	32.7	— 7.3	32.4
Other Oils	143.7	135.7	+ 5.9	140.7	.....	.....	.....	.....

U.S. Crude Oil Production, by States (Thous. Bbls.)

STATE or DISTRICT	Daily Average for Month Nov. 1959	Nov. 1958	% Diff.	Oct. 1959	Total, January-November 1959	1958	% Diff.
Alabama	16.1	15.4	+ 4.5	16.1	4,659	5,408	— 13.8
Arkansas	54.3	78.2	— 30.6	52.4	23,685	26,284	— 9.9
California	837.4	854.1	— 2.0	838.7	281,430	288,086	— 2.3
Colorado	127.8	127.0	+ 0.6	127.2	42,156	44,363	— 5.0
Florida	1.2	1.3	— 7.7	1.2	389	411	— 5.4
Illinois	218.8	223.0	— 1.9	214.4	71,709	75,072	— 4.5
Indiana	31.9	34.6	— 7.8	31.6	10,964	10,822	+ 1.3
Kansas	326.5	332.9	— 1.9	325.7	109,358	108,103	+ 1.2
Kentucky	68.9	57.3	+ 20.2	72.3	24,527	15,625	+ 57.0
Louisiana	1,033.8	916.9	+ 12.7	1,014.1	321,900	283,354	+ 13.6
North Louisiana	113.5	111.2	+ 2.1	113.3	40,509	38,100	+ 6.3
South Louisiana	920.3	805.7	+ 14.2	900.8	281,391	245,254	+ 14.7
Michigan	32.8	24.6	+ 33.3	31.5	9,431	8,462	+ 11.5
Mississippi	144.3	121.7	+ 18.6	141.9	43,441	34,952	+ 24.3
Mo.-So. Dak.-Tenn.	0.5	0.1	+400.0	0.5	95	111	— 14.4
Montana	80.8	75.9	+ 6.4	80.2	27,403	25,822	+ 6.1
Nebraska	63.2	57.3	+ 10.3	65.8	21,337	18,611	+ 14.6
Nev.-Wash.-Alaska-Ariz.	0.5	0.2	+150.0	0.5	192	41	+368.3
New Mexico	292.5	273.5	+ 6.9	291.8	96,461	89,622	+ 7.6
Southeast New Mexico	253.6	242.9	+ 4.4	252.1	83,209	82,257	+ 1.1
Northwest New Mexico	38.9	30.6	+ 27.1	39.7	13,252	7,365	+ 79.9
New York	5.4	2.6	+107.7	5.4	1,807	1,578	+ 14.5
North Dakota	50.6	41.8	+ 21.0	44.1	16,334	12,766	+ 27.9
Ohio	12.9	15.9	— 18.9	13.6	5,041	5,757	— 12.4
Oklahoma	539.6	557.8	— 3.3	522.1	179,081	185,353	— 3.4
Pennsylvania	16.9	16.1	+ 5.0	16.3	5,540	6,176	— 10.3
Texas	2,529.6	2,744.2	— 7.8	2,485.3	898,162	852,296	+ 5.4
Dist. 1: South Central	45.9	47.5	— 3.4	44.5	15,161	15,448	— 1.9
Dist. 2: Middle Gulf	112.6	125.1	— 10.0	109.9	39,340	38,408	+ 2.4
Dist. 3: Upper Gulf	355.7	393.6	— 9.6	350.1	127,127	125,006	+ 1.7
Dist. 4: Lower Gulf	180.6	203.6	— 11.3	178.4	63,705	63,203	+ 0.8
Dist. 5: East Central	25.4	30.4	— 16.4	27.2	9,902	9,998	— 1.0
Dist. 6: Northeast	244.7	277.3	— 11.8	240.6	87,833	85,745	+ 2.4
Dist. 7-B: North Central	126.5	138.3	— 8.5	131.9	51,801	45,616	+ 13.5
Dist. 7-C: West Central	122.1	144.7	— 15.6	118.5	42,758	44,345	— 3.6
Dist. 8: West	1,005.7	1,072.6	— 6.2	974.5	352,209	315,065	+ 11.8
Dist. 9: North	203.2	209.3	— 2.9	201.8	68,983	66,565	+ 3.6
Dist. 10: Panhandle	107.2	102.0	+ 5.1	107.9	35,979	35,469	+ 1.4
Utah	100.3	73.1	+ 37.2	106.9	36,431	21,507	+ 69.4
Virginia	.....	.....	.....	.....	5	6	— 16.7
West Virginia	5.6	5.7	— 1.8	6.3	1,986	2,012	— 1.3
Wyoming	342.9	332.7	+ 3.1	349.3	114,969	105,027	+ 9.5
Total, U.S.	6,935.1	6,983.9	— 0.7	6,855.2	2,348,493	2,227,627	+ 5.4

Sources for above 3 tables: Bureau of Mines monthly reports, except last two months based on API and B. of M. weekly reports and WORLD OIL estimates, and all Texas districts from API.

000 barrels daily was 123,000 barrels or 7.9 percent greater than in November 1958.

Gasoline demand of 3,941,000 barrels daily was 166,000 daily or 4.4 percent higher than in November 1958, and set a new November record.

Gains for year. For the first 11 months of 1959, total demand for all oils averaged 9,550,000 barrels daily, up 412,000 barrels or 4.5 percent over the first 11 months of 1958. Exports have been lower, but domestic demand has been 450,000 barrels a day or 5.1 percent greater.

For January-November, 1959, gasoline demand averaged 4,125,000 barrels daily, up 164,000 daily or 4.1 percent over 1958. Residual fuel oil demand of 1,584,000 barrels daily was up 108,000 daily or 7.3 percent. Distillate fuel demand of 1,779,000 barrels per day was up 63,000 daily or 3.7 percent.

Supply is moderate. Despite the strong trends of demand, new supplies of oils were held at conservative levels in November. They were increased only moderately in a season when some expansion is normal.

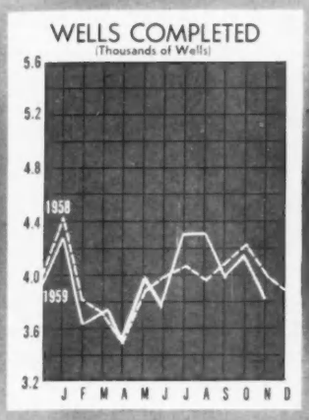
Total new supply of 9,626,000 barrels daily in November was 345,000 barrels more than in October but only 42,000 a day or 4/10 of 1 percent more than in November 1958. Both domestic production and imports were only slightly higher than in November 1958.

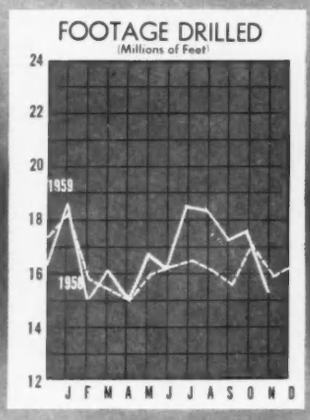
Stocks Reduced. With production and imports held low, despite strong demand, the industry in November 1959 drew heavily on stocks of both crude and refined oils.

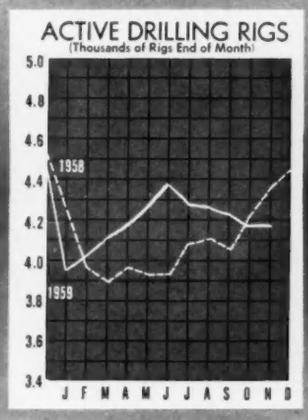
Refinery runs were stepped up by 250,000 barrels daily to 7,917,000 daily in November from 7,667,000 in October but were then only 141,000 daily or 1.8 percent above November 1958. With new supplies of crude limited, stocks of crude were drawn down by 123,000 barrels daily to only 252,600,000 barrels.

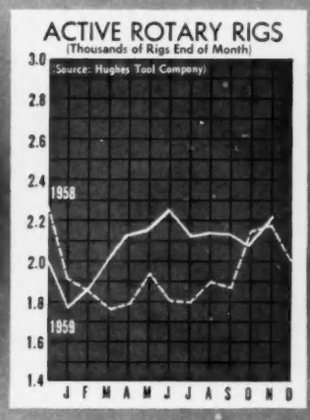
To meet market requirements, stocks of products were used to the extent of 450,000 barrels daily. Gasoline stocks were increased 147,000 barrels daily and miscellaneous oils 100,000 daily. But there were withdrawals averaging 523,000 barrels daily of distillate, 70,000 daily of kerosine, and 103,000 daily of residual.

Drilling Activities...









Sharp increase in gas wildcats

FOLLOWING A SEASONAL trend, total footage and new well completions nosedived in November. However, rigs operating at month's end were up slightly over October. The November report in brief:

Total rigs operating on November 30 . . . 4,178, up 33 rigs over the October 31 total, but down 232 rigs or 5.3 percent from the same date in 1958.

November daily completions . . . 126 wells per day, down 9.7 percent from the 136 wells per day average in October, and in November 1958. November's was the lowest daily average since April when an average of 119 new completions per day were reported.

Average daily footage . . . 510,000 feet, down 10 percent from the 567,742 feet per day drilled in October, and down 3.8 percent from the November 1958 daily average of 530,000 feet. Last November's daily average was only slightly higher than April's 1959 low of 523,000 feet per day.

Gas and condensate wildcats were the only phases of drilling activity showing increases during the first 11 months, with the gas wildcat total up 26 percent to 257 wells.

Summary of U.S. Wildcat Drilling

ITEM	Nov. 1959	Oct. 1959	ELEVEN MONTHS January-November 1959	1958	% Diff.
New Field Discoveries:					
Oil	60	50	647	678	— 4.6
Distillate	6	4	82	80	+ 2.5
Gas	40	30	257	204	+ 26.0
Total Discoveries	**106**	**84**	**986**	**962**	**+ 2.5**
Dry Wildcats	**728**	**838**	**8,029**	**8,020**	**+ 0.1**
Total Wildcats	**834**	**922**	**9,015**	**8,982**	**+ 0.4**
(Percent Productive)	12.7	9.1	10.9	10.7	
(Percent Dry)	87.3	90.9	89.1	89.3	

Summary of U.S. Drilling Activity

ITEM	Nov. 1959	Oct. 1959	ELEVEN MONTHS January-November 1959	1958	% Diff.
New Wells Completed:					
Oil	1,817	2,002	22,088	22,047	+ 0.2
Distillate	48	62	733	667	+ 9.9
Gas	378	370	3,743	3,950	— 5.2
Service	47	73	722	1,184	— 39.0
Dry	1,501	1,691	16,944	16,781	+ 1.0
Total New Wells	**3,791**	**4,198**	**44,230**	**44,629**	**— 0.9**
Footage Drilled (Millions of Feet)	**15.3**	**17.6**	**185.2**	**178.8**	**+ 3.6**

U.S. Drilling Activity in November and First Eleven Months, 1959-1958

STATE or DISTRICT	TOTAL NEW WELLS COMPLETED AND FOOTAGE DRILLED: DETAILS FOR NOVEMBER, 1959 — Oil	Dist.	Gas	Dry	Service Wells	TOTAL NEW WELLS — Nov. 1959	Oct. 1959	Nov. 1958	Total Footage November 1959	DETAILS FOR JANUARY-NOVEMBER — NEW WELLS — 1959	1958	Percent Diff.	FOOTAGE — 1959	1958	WILDCAT DRILLING IN NOVEMBER AND FIRST ELEVEN MONTHS, 1959-1958 — DETAILS FOR November, 1959 — Oil	Dist.	Gas	Dry	Total Wildcats	DETAILS FOR JANUARY-NOVEMBER — Oil	Dist.	Gas	Dry	TOTAL WILDCATS — 1959	1958	DRILLING RIGS IN OPERATION (Rigging up, Drilling Temp. Shut-Down) — Nov. 30, 1959	Oct. 31, 1959	Nov. 30, 1958
Ala'ama	9	....	....	....	....	9	7	5	85,941	99	74	+ 33.8	895,448	610,106	....	....	....	....	....	....	....	....	28	28	27	6	9	18
Alaska	1	....	....	1	....	2	2	....	20,847	10	....	....	110,485	....	....	....	....	1	1	1	....	1	6	8	....	6	7	....
Arkansas	36	....	4	29	....	69	81	80	242,716	756	751	+ 0.7	2,543,204	2,508,015	3	....	2	10	15	7	....	10	104	121	144	45	48	43
California	73	....	12	54	4	143	142	105	618,991	1,351	1,298	+ 4.1	6,459,252	6,194,642	1	....	....	33	34	6	....	6	280	292	278	119	139	142
Colorado	7	....	6	15	....	28	80	70	144,166	662	789	— 16.1	3,485,356	4,082,935	2	....	1	13	16	23	....	16	314	353	442	45	40	59
Florida	....	....	....	2	....	2	1	....	13,054	9	6	+ 50.0	73,397	55,809	....	....	....	2	2	....	....	....	9	9	6	1	3	1
Illinois	89	....	4	120	....	213	170	287	444,335	1,912	2,184	— 12.5	4,210,431	5,009,378	1	....	....	62	63	11	....	....	461	472	555	336	303	306
Indiana	22	....	....	55	1	78	97	99	112,187	815	809	+ 0.7	1,276,560	1,304,836	....	....	....	23	23	2	....	1	225	228	231	94	121	112
Kansas	141	....	24	180	6	351	306	337	1,300,885	3,444	3,415	+ 0.8	12,640,924	11,761,314	16	....	6	88	110	130	....	28	908	1,056	897	305	294	327
Kentucky	136	....	23	90	1	250	267	229	223,568	2,685	2,135	+ 25.8	2,432,600	2,194,285	....	....	....	5	5	10	....	....	71	81	73	200	190	107
Louisiana	165	18	16	96	....	295	333	311	2,060,282	3,472	3,204	+ 8.4	26,756,989	24,705,303	3	2	1	35	41	27	15	13	438	493	540	329	333	374
North Louisiana	88	....	8	48	....	144	144	142	460,643	1,376	1,268	+ 8.5	4,835,061	4,688,361	2	....	1	15	18	15	1	5	168	189	191	65	67	75
South Louisiana	77	18	8	48	....	151	189	169	1,599,639	2,096	1,936	+ 8.3	21,921,928	20,016,942	1	2	....	20	23	12	14	8	270	304	349	264	266	299
*Gulf of Mexico	19	2	1	4	..	26	41	33	266,438	423	451	— 6.2	4,371,894	4,327,830	....	1	....	2	3	2	3	4	25	34	38	48	54	42
Michigan	22	....	11	33	....	66	59	36	204,116	548	356	+ 53.9	1,691,711	1,020,399	1	....	1	20	22	4	....	4	143	151	122	95	102	84
Mississippi	21	....	1	23	....	45	63	40	444,525	593	364	+ 62.9	5,545,887	3,216,393	....	....	....	17	17	8	1	2	211	222	141	86	69	71
Missouri	....	....	....	2	....	2	....	....	3,000	14	15	— 6.7	12,901	15,612	....	....	....	1	1	1	....	....	10	11	8	2	2	3
Montana	9	....	3	13	....	25	45	28	106,257	298	281	+ 6.0	1,434,147	1,470,852	....	....	1	8	9	2	....	1	94	97	109	47	42	59
Nebraska	10	....	....	26	....	36	77	71	208,105	755	639	+ 18.2	4,493,143	3,813,927	2	....	....	13	15	36	....	....	301	337	298	20	24	27
New Mexico	109	....	48	36	3	196	166	170	782,305	1,652	1,829	— 9.7	6,866,880	8,545,507	..	....	5	22	27	31	1	26	188	246	260	167	166	162
Southeast	76	....	3	23	....	102	104	80	407,328	907	912	— 0.6	4,225,991	4,554,563	....	....	....	....	....	22	....	5	138	165	167	95	97	73
Northwest	33	....	45	13	3	94	62	90	374,977	745	917	— 18.8	2,640,886	3,990,944	....	....	5	22	27	9	1	21	50	81	93	72	69	89
New York	10	....	1	2	6	19	19	23	30,895	207	222	— 6.8	329,770	350,619	....	....	....	....	....	....	....	....	....	....	....	25	25	42
North Dakota	19	....	....	9	....	28	20	30	194,594	382	385	— 0.8	2,429,973	2,491,993	1	....	....	4	5	13	....	....	54	67	115	22	27	28
Ohio	67	....	26	39	....	132	114	88	318,858	954	906	+ 6.4	2,476,163	2,346,540	1	....	3	7	11	6	....	7	21	34	10	212	213	218
Oklahoma	72	....	30	67	....	169	385	504	527,584	4,855	6,459	— 24.8	17,707,087	20,082,007	8	....	7	35	50	70	12	34	564	680	703	466	468	547
Pennsylvania	20	....	27	8	10	65	63	71	192,263	633	716	— 11.6	1,977,834	2,135,202	....	....	....	1	1	....	....	4	17	21	26	195	189	213
South Dakota	1	....	....	4	....	5	4	....	43,316	20	6	+233.3	142,711	26,804	....	....	....	4	4	3	....	....	10	13	6	3	2	2
Tennessee	....	....	....	5	....	5	6	2	5,000	97	26	+273.1	97,356	32,975	....	....	....	5	5	....	....	....	51	51	9	25	25	....
Texas	725	30	87	501	15	1,358	1,514	1,329	6,064,016	16,194	15,940	+ 1.6	71,559,138	67,532,749	17	4	11	257	289	231	52	91	3,145	3,519	3,668	1,021	973	1,093
Dist. 1: South Central	45	3	....	36	....	84	85	64	253,347	883	881	+ 0.2	2,301,654	2,151,023	....	1	....	23	24	7	1	1	270	279	295	35	39	38
Dist. 2: Middle Gulf	17	9	12	32	....	70	77	53	419,854	737	643	+ 14.6	4,600,526	3,940,547	....	....	2	17	19	10	13	14	223	260	227	48	42	32
Dist. 3: Upper Gulf	32	11	8	41	....	92	83	99	682,201	1,083	1,172	— 7.6	7,734,553	7,544,595	....	2	1	22	25	9	23	9	219	260	321	106	107	107
*Gulf of Mexico	1	....	....	2	....	3	....	....	28,856	5	11	— 54.6	49,112	86,748	....	....	....	2	2	....	....	1	3	4	9	....	2	....
Dist. 4: Lower Gulf-S.W.	25	6	12	32	....	75	112	66	407,790	1,208	1,030	+ 17.3	6,527,511	5,347,492	1	1	....	23	25	15	12	10	337	374	412	74	81	87
*Gulf of Mexico	....	....	....	....	....	....	....	1	....	1	8	— 87.5	500	84,048	....	....	....	....	....	....	....	....	1	1	3	....	....	....
Dist. 5: East Central	....	....	4	11	....	15	17	13	100,921	140	179	— 21.8	750,138	676,493	....	....	1	6	7	2	....	2	58	62	104	15	19	16
Dist. 6: Northeast	31	....	5	35	....	71	62	71	393,123	763	766	— 0.4	4,177,935	4,097,390	....	....	....	19	19	10	1	7	144	162	190	59	57	58
Dist. 7-B North Central	88	....	7	94	3	192	216	161	616,477	2,221	1,980	+ 12.2	7,137,470	6,301,033	4	....	3	49	56	59	1	15	650	725	705	100	104	93
Dist. 7-C West Central	26	....	1	30	1	58	66	50	276,367	698	707	— 1.3	3,007,692	3,446,592	1	....	....	21	22	23	....	10	199	232	201	68	61	57
Dist. 8: West	259	....	10	47	6	322	390	316	1,705,177	4,143	3,858	+ 7.4	21,270,330	18,738,676	8	....	1	21	33	59	....	7	419	515	481	287	243	369
Dist. 9: North	147	....	7	126	5	285	273	321	761,641	3,177	3,491	— 9.1	8,849,383	9,907,948	2	....	....	41	46	23	....	2	482	507	604	146	134	146
Dist. 10: Panhandle	55	1	21	17	....	94	133	115	446,118	1,141	1,230	— 7.2	5,198,946	5,377,959	1	....	3	9	13	14	1	14	114	143	127	83	86	90
Utah	12	....	4	16	....	32	16	24	171,304	259	370	— 30.0	1,445,315	2,053,883	....	....	1	12	13	5	....	3	65	73	78	28	25	39
Washington	....	....	....	....	....	....	1	....	....	3	6	— 50.0	21,108	33,282	....	....	....	....	....	....	....	....	3	3	5	1	2	1
West Virginia	8	....	43	11	....	62	71	71	164,739	713	763	— 6.6	1,822,413	2,043,863	....	....	....	....	....	....	....	....	1	1	6	186	213	213
Wyoming	33	....	8	53	1	95	90	65	523,533	788	637	+ 23.7	4,134,058	3,003,384	4	....	1	40	45	19	1	9	275	304	209	85	83	115
Others	....	....	....	11	....	11	5	12	29,244	40	44	— 7.0	118,788	184,525	....	....	....	10	10	1	....	1	32	34	25	6	8	4
Total United States	1,817	48	378	1,501	47	3,791	4,204	4,087	15,280,676	41,230	41,629	— 0.9	185,192,012	178,830,199	60	6	40	728	834	647	82	257	8,029	9,015	8,982	4,178	4,145	4,410
Total Western Canada	100	....	20	30	....	150	187	199	750,000	2,203	2,350	— 6.1	10,946,151	11,659,271	....	....	....	....	....	....	....	....	....	....	....	193	202	219

*Gulf of Mexico wells are included in their respective district totals.

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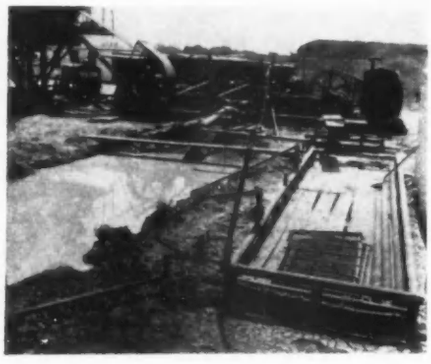
Use Adjustable Choke On Input Gas Line

Installation of an adjustable choke on the input line of a gas lift well provides maximum control of injection gas when an intermitter is not used. Since the well illustrated in the photograph requires a constant gas injection, the operator found installation of an adjustable choke saves a considerable amount of time when adjusting gas input rates.

With the adjustable choke, the pumper does not have to install and remove several positive chokes to obtain a given injection rate.



Make a Skid-Mounted Bin To Handle Mud Additives

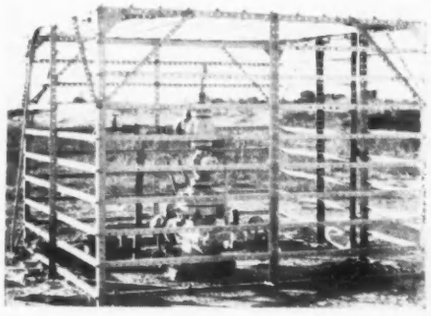
A skid-mounted bin can be made to carry drilling mud additives between locations, yet be ready to feed into the mud hopper without further handling. The bin is approximately 7½ feet wide by 20 feet long and is 1 foot deep. Frame is made of 4-inch drill pipe and the railing around the top serves a jet line from the auxiliary mud mixing pump.

In operation, the bin is placed along the mud pits and the railing around the top is connected into the auxiliary pump. Jet lines are then set up along the sides of the pit. These can be swung over the bin when the assembly is on the road. The sacks of mud additives are placed inside the bin and fed into the hopper as needed. The hopper is permanently mounted on the front corner of the bin. When it is time to move, the mud pump is disconnected and the lines swung over the remaining sacks of mud and the entire rig is sucked up onto the moving truck.

Simple Clips Lock Pipe Rack Sections Together

Maximum strength combined with ease and simplicity of rigging are principal features of this efficient pipe rack. Made primarily of drill pipe material, the all-welded rack sections are locked together without bolts or drive pins. Instead, positive self-locking clips are welded to the ends of the 2½-inch tubing transverse sections which tie front and back rack members together.

Shown in detail in the photograph, the clips are made of heavy steel plate and once dropped into position, cannot be lifted out accidentally. A safety bolt is run through a hole in the vertical post immediately above the clip. The sections thus become rigidly locked trusses that cannot lean or skid sideways, yet can be dismantled rapidly when pipe is removed from the rack.



Angle Iron Guard Protects This Well From High Water

A guard made of angle iron protects this coastal well from damage by floating debris or loose equipment during high water periods.

The guard completely encloses the well and is easily removed should a rig have to be moved onto the hole.

Rags and Bailing Wire Prevent Gas Line Freezing

This lease operator has successfully employed a simple method to prevent supply gas lines from freezing in cold weather. Supply gas for the diaphragm dump valve is obtained through a length of copper tubing tied into the top of the separator. Because the gas is wet, the line has a tendency to freeze and plug in cold weather which results in dump valve failure.

The lease pumper simply used a supply of waste rags and bailing wire to wrap the copper tubing throughout its length from the top of the separator to the drip. This provides sufficient insulation to prevent the line from freezing.

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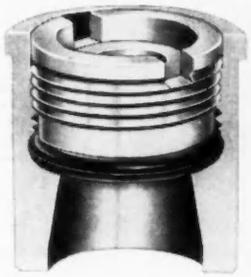

Smith threaded flow nozzle sectioned to illustrate o-ring seal and general construction.

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Make Heavy-Duty Holders From Scrap Tool Joints

Use scrap tool joints as heavy-duty stands around the rig. Cut the tool joint off immediately below the collar on a bevel which conforms to the adjoining member. Then weld in place, with the threaded end in an upright position. This holder has several uses. One is to hold poles, should an electric line be strung to the vicinity of the mud tank.

Radiator Protection Grating Used to Dry Wet Gloves

The crew of a Gulf Coast rig uses the protection grating on the radiator of the rig engines as a holder to dry wet work gloves. The gloves are hung up and held in place by simply inserting a finger of the glove into the openings of the gratings.

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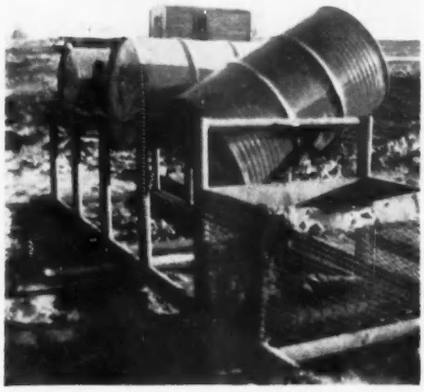
Eliminate Well Fence Gate, Build Steps into Guard Rail

This operator has devised a unique method for providing entrance to fenced well locations. A series of steps have been built into the guard rail as shown. With such a set-up, a gate is not needed and a very neat appearing installation results.

The opening in the guard rail is made by cutting a 3-foot section out of the top rail and using equal lengths of junk pipe to form supports for the top rail by welding the two pieces of pipe between the top and bottom sections of the fence. The steps then are positioned in front of this opening and will provide access to the well while preventing livestock from entering the location.



Build a Skid-Mounted Rack for Oil Drums

A skid-mounted support will keep oil drums readily available around the rig. A spare parts bin is located at one end of the rack. It is enclosed with 1-inch-by-1-inch steel wire. The entire support can be lifted and moved as a single unit. The framework is made of 2-inch pipe welded together. The skids are made of 4½-inch drill pipe.

Use Scrap Tin to Prevent Pollution at Lease Pump

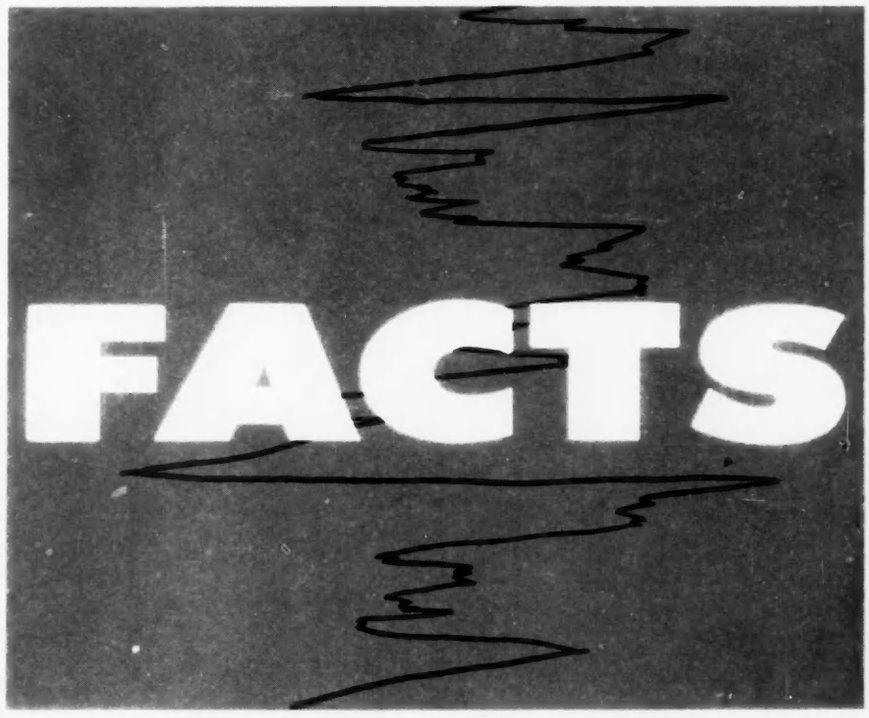
Here is an economical method of preventing oil and salt water pollution around lease fire-wall pumps.

A piece of scrap tin is bent on each end and installed beneath the fluid end packing glands of pump. If packing glands become loose, or if the rod packing begins leaking for any reason, the lost fluid drips into the tin tray.

The far portion (behind the pump) of the tin tray is bent into a junk section of 4-inch pipe which extends into a pit adjacent to the fire wall. Fluid which has leaked onto the tray flows into the pipe and is safely deposited in the disposal pit. Use of such a set-up prevents leakage of oil, salt water and contributes in general to good housekeeping practice.

Mount the Changehouse On a Two-Wheel Trailer

In highly mobile operations, the changehouse can be mounted on a two-wheel trailer that is pulled behind the pusher's car. Build benches along the walls of the trailer. For added support on location, support the back of the trailer with a commercial type automobile jack.



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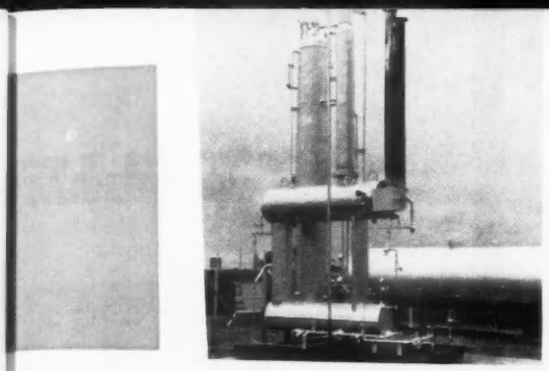
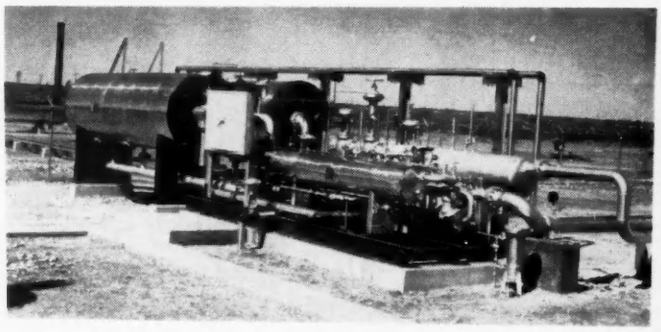
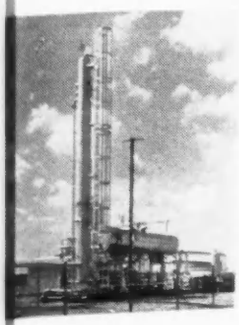
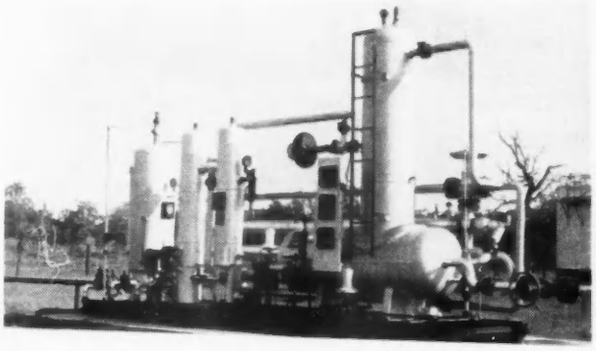
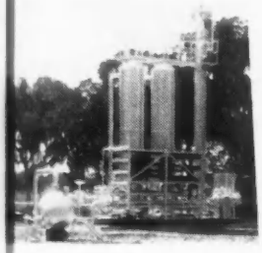


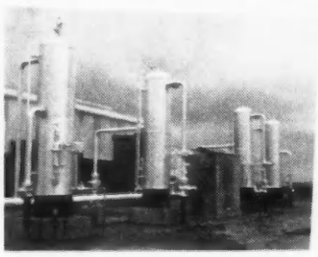


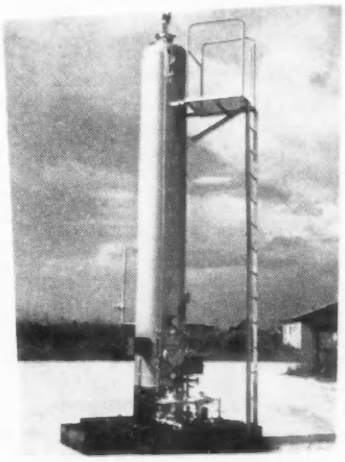


PRODUCING EQUIPMENT FOR NATURAL GAS WELLS









TEN YEARS AGO you could scarcely find a small producer willing to spend the time and money necessary to make his natural gas reserves marketable. The return on capital investment was too low, and equipment costs were too high.

No longer is that true. An increasing number of natural gas producers, both large and small, are installing their own separation, dehydration and hydrocarbon recovery equipment.

Why the New Trend?

. . . Interest in natural gas production has increased rapidly during the past few years—in direct proportion to its increasing market value.

. . . Tight proration schedules and weak price structures have cut deeply into the financial incentive of crude oil. Today

a "good" gas well will provide considerably more revenue than a "good" oil well.

. . . Development of the low temperature, adsorption and other processes has made it possible for the small producer to put in unattended and relatively cheap units to recover liquid hydrocarbons.

Needed: A Complete, Authoritative Manual on Natural Gas Producing Equipment

In keeping with the new trend, a growing number of production personnel are required to specify, select and buy gas well equipment. As WORLD OIL surveys indicate, this increased activity has created an urgent need for a single source of information that describes and illustrates in detail separation, dehydration and hydrocarbon recovery equipment.

To meet this need, WORLD OIL is presenting in this issue, and in two following issues, the first **Production Practices Manual** on **Equipment Used in Producing Natural Gas**—written especially for the production man.

The **Manual** contains the most complete, authoritative, up-to-date information available. To insure a top quality presentation, WORLD OIL spent the past 10 months contacting the men most qualified to describe gas well producing equipment—the equipment manufacturers. Seven authors from five different manufacturers have contributed to this cooperative effort.

Each section of the **Manual** was checked and approved by all authors, assuring an exclusive, correct, straightforward presentation.

What the Manual Contains

In this issue you will find a complete description of:

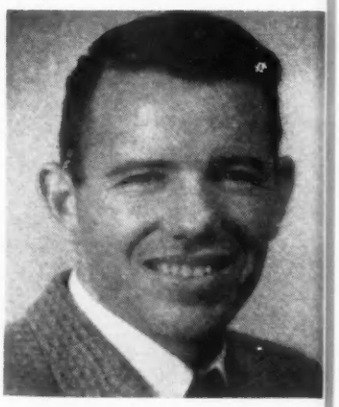
- **Conventional Separators . . . Page 84.**
- **Mechanical Low Temperature Separation Units . . . Page 93.**
- **Long Cycle Dry Desiccant Dehydrators . . . Page 100.**
- **Calcium Chloride Dehydrators . . . Page 105.**

The February 1 and March 1 issues of WORLD OIL will describe and illustrate in detail:

- Glycol dehydrators.
- Short cycle dry desiccant hydrocarbon recovery units.
- Ammonia refrigeration units as applied to low temperature separation.
- Indirect flow line heaters.
- Instrumentation for field units.
- Three-phase (oil, gas, water) separators.

Each of the **Manual's** three sections includes the following: *Discussion of basic equipment, including flow diagrams and schematic drawings—How each type unit operates—Advantages and disadvantages—Recommended operating practices—Trouble shooting information.*

THE



J. B. Fowler

Jim Loomer, after graduating from the University of Oklahoma with a B.S. degree in chemical engineering joined Black, Sivalls & Bryson, Inc. He is now supervisor of the Engineering Standards Group for the Oil Field Division of BS&B. His experience has been primarily in the field of natural gasoline and gas processing where he has worked as a design engineer and field project engineer.

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J. B. Fowler is a sales and application engineer with the Climax Controls Division of Black, Sivalls & Bryson, Inc., in Houston. He attended Texas A&M College and was graduated in 1952 with a degree in industrial psychology. Following two years in the military service, he joined Union Tank and Supply Company in 1954 as a sales engineer. After two years with Union Tank, he joined BS&B.

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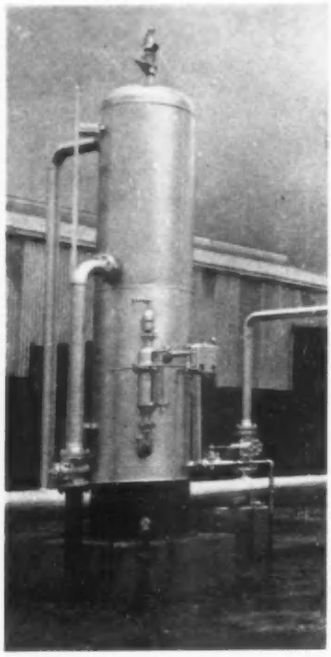
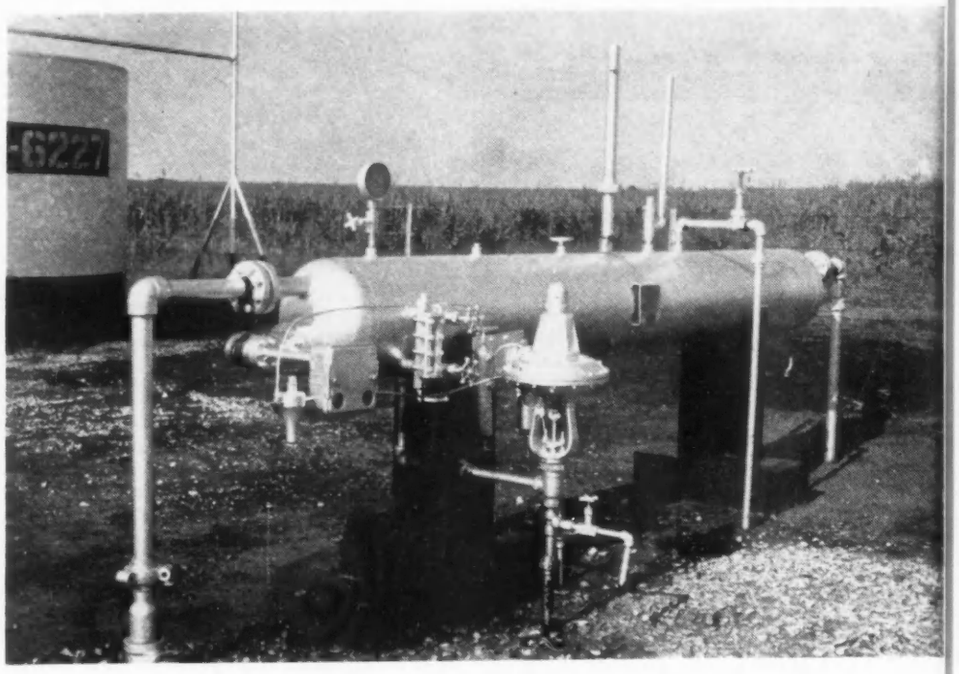
J. Roger Heumann is a technical service specialist in process equipment for Black, Sivalls & Bryson, Inc., in Houston. He holds a B.S. degree in chemical engineering from the University of Oklahoma (1948) and a B.S. degree in business from Oklahoma City University (1957). Heumann joined Pan American Petroleum Corporation (then Stanolind Oil and Gas Company) after graduation from Oklahoma. He worked at various times in a project group, gas development group, engineering construction and the estimating section. In 1953, he transferred to the mechanical equipment section of the Production Department. Heumann joined BS&B in 1954 in the product development section of the Engineering Department. In 1955 he moved to the gasoline plant group of the Engineering Department as a process engineer and project engineer. He assumed his present position in 1958. He is a registered professional engineer in the State of Oklahoma.

R. H. Ackermann has done extensive work on calcium chloride dehydrators as a process engineer with Rolo Manufacturing Company in Houston since 1957. He received a B.S. degree in chemical engineering from The University of Texas in 1949. From 1950 until 1954 he worked as an engineer with Sinclair Refining Company. His duties included evaluating crude oils, developing routine methods of chemical analysis, designing pilot plants, and other operational engineering duties. In 1954 and 1955 he worked as a process engineer with The Parkersburg Rig & Reel Company. Before joining Rolo he also served as a process engineer for a consulting group, a thermal design engineer for Brown Fintube Company, and project engineer for Dale S. Cooper and Associates. He is a registered professional engineer in the State of Texas.

George J. Mapes is a product application specialist for The Parkersburg Rig & Reel Company in Houston. His duties include answering product inquiries and preparing technical articles for publication. Mapes attended the University of Houston where he majored in mechanical engineering.



Typical oil and gas separator



Single barrel horizontal separator

1. THE OIL AND GAS SEPARATOR

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OIL AND GAS SEPARATORS are one of the most basic items of producing equipment used in the field today. Although separators are used widely in the oil country they still must be selected with care for particular applications. Proper consideration of liquid and gas capacities for the different type units and careful application of correct operating procedures will result in trouble free, unattended operation for long periods.

The separator vessel is constructed in the following basic shapes:

- Vertical cylindrical (Figure 1)
- Horizontal cylindrical (Figures 2 and 3)
  a. single barrel—one horizontal cylinder
  b. double barrel—two horizontal cylinders stacked one on top of the other
- Spherical (Figure 4).

This article will discuss advantages and disadvantages of the various separator vessels and will consider methods for selecting the proper type for a particular application.

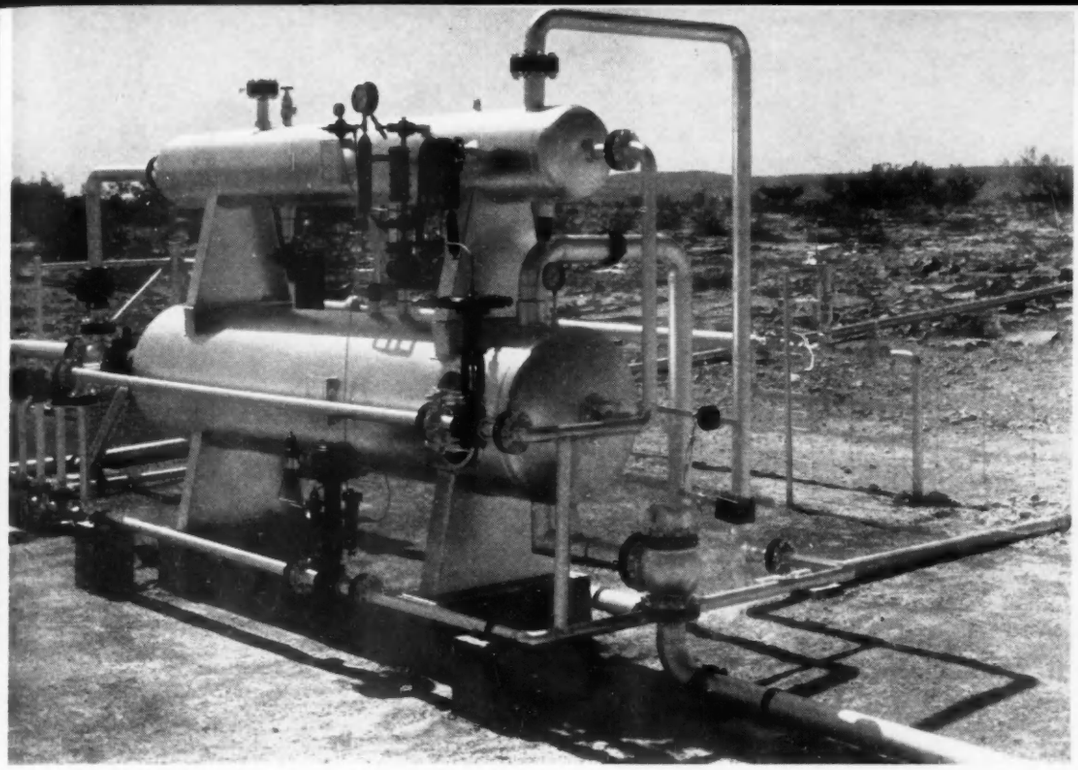
NOMENCLATURE

Depending on application, a separator vessel may be referred to as a knockout, scrubber, filter, flash chamber or expansion vessel as well as the original term. This terminology is applied regardless of shape, and is often not clear. Generally, the following definitions are regarded as basic:

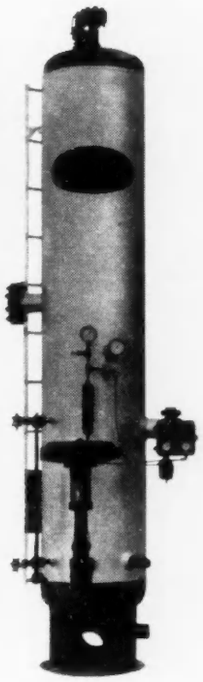
Separator. A separator is used primarily to separate a combined liquid-gas stream into components that are relatively free of each other.

The name Separator usually is applied to the vessel used in the field to separate oil and gas coming directly from an oil or gas well, or group of wells. The ratio of gas to liquid handled will be in the range normally produced from gas or oil wells. Instantaneously low ratios (large amounts of liquid) can occur due to well heading, surging, or slugging conditions in well flow lines or gathering lines.

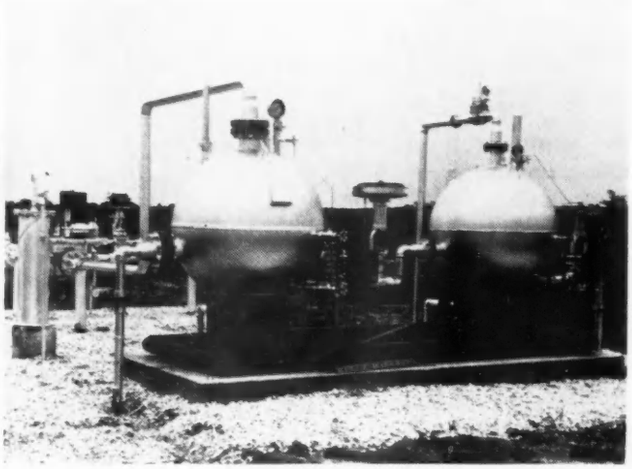
Scrubber. A scrubber is a separator which has been designed to handle streams with unusually high gas to liquid ratios.



Double barrel horizontal separator



Vertical separator



Spherical separator

The term Scrubber is applied to a vessel normally more efficient (but not necessarily so) than conventional separators in removing fine liquid particles from a gas stream. A scrubber usually is applied downstream of the field separator or separators to remove entrained and/or condensed liquid. Scrubber also can refer to a vessel used ahead of a dehydrator, extraction plant or compressor to protect this type of equipment from entrained liquid.

Knockout. Knockouts also are separators and fall into two categories: free water and total liquid knockouts. The *free water knockout* is a vessel used to separate free water from a combined gas, hydrocarbon liquid and water stream. The gas and hydrocarbon liquid usually are allowed to leave the vessel together through the same outlet to be processed by other equipment. The water is removed for disposal. A free water knockout can be utilized at either high or low pressure.

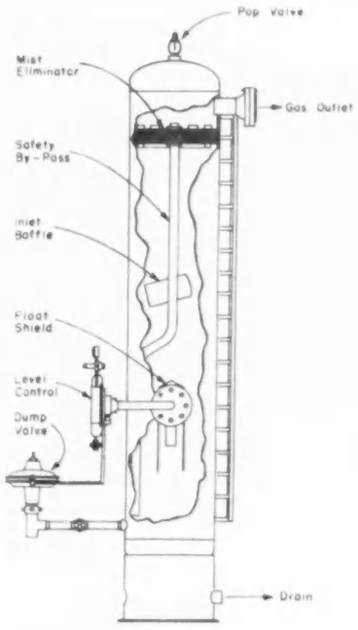
The *total liquid knockout* is normally used to remove liquids from a high pressure gas stream (3,000 psig and above). This vessel usually is used with a cold separation unit.

Flash chamber. This is a vessel used as a subsequent stage of separation to process the liquid hydrocarbons flashed from a primary separator. The name is applied to the vessel used as a second stage separator on a cold separation unit. The vessel is usually of low pressure design—not more than 125 psig working pressure. It rarely differs from the conventional low pressure separator.

Expansion vessel. This name is applied to the vessel into which gas is expanded for a cold separation application. It also is referred to as a cold separator or a low temperature separator. The vessel differs considerably from the normal separator since it is designed primarily to handle and melt gas hydrates that are formed by expansion cooling. In cold separation applications where a hydrate preventative is used, the design may be very close to that of a normal separator. The usual working pressure of this vessel is in the range of 1,000 to 1,500 psig.

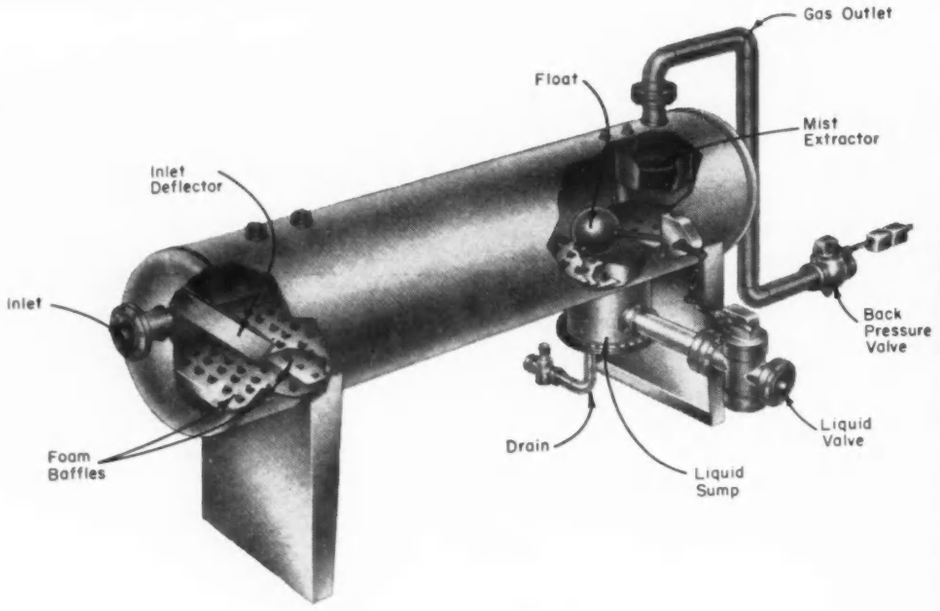
Filter—(dust scrubber). Where liquid is present to a fair degree in a gas stream, the conventional oil and gas separator will remove any solid particles in the stream. The liquid acts to trap the solids in the mist extractor (or coalescer) and other sections of the separator. It then serves as a medium to flow the solids out of the vessel.

When gas is dry, there are still solid particles present to interfere with some phases of gas transmission and



Vertical Separator

FIGURE 1



Single Barrel Horizontal Separator

FIGURE 2

distribution. The vessel designed to remove these solids is called a Filter or Dust Scrubber. The *filter* normally uses a dry filter pack to trap undesirable particles. These filter packs require periodic removal for changing or cleaning.

The *dust scrubber* uses an oil bath (or similar liquid bath) to trap the dust particles. Operation then is quite similar to a conventional separator.

Any shape vessel can be used for the designs implied by the preceding definitions. Naturally, one shape will suffice better than another for a specific need. This applies not only to internal design requirements, but also to application of the finished vessel.

DESIGN

Regardless of shape, a modern separation vessel will contain four parts:

The primary or initial separation section. This section is used to collect the main portion of liquid in the inlet stream. It contains the inlet nozzle, which is usually tangential, or a diverter baffle to take advantage of as much of the available vessel volume as possible. Centrifugal force or an abrupt change of direction is used to throw the major portion of entrained liquid from the gas stream.

The secondary or gravity settling section. This section normally is designed to utilize the force of gravity. It consists of a portion of the vessel through which the gas moves at a relatively low velocity with little turbulence. In some designs, straightening vanes are used to reduce turbulence. The vanes also act as droplet collectors, and their use reduces the distance a droplet must fall to be removed from the gas stream.

The mist extraction or coalescing section. This section utilizes a mist extractor which can be one of several designs (a series of vanes, woven wire mesh pad or cyclonic passage). Many of the more recent designs use the woven wire mesh pad. The mist extractor removes the very small droplets (down to ten micron diameter) of liquid in one final separation before the gas leaves the vessel.

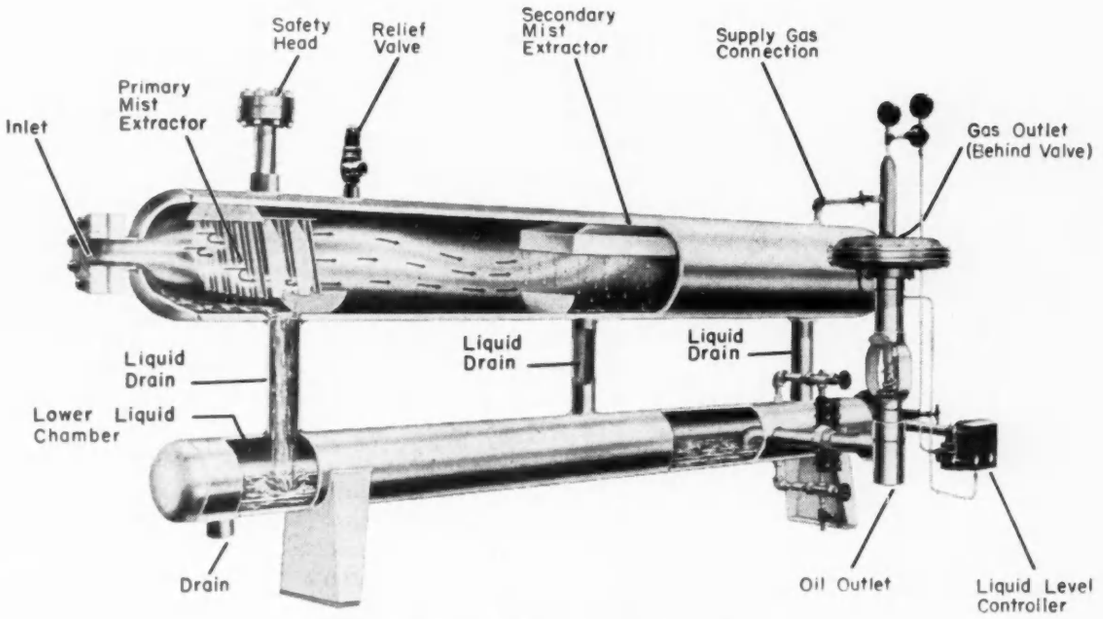
The sump or liquid collecting section. This section acts as receiver for all liquid removed from the gas in the three sections discussed previously. Room is provided for the installation of a liquid level control device. Depending on shape and requirements, the liquid section would have a certain amount of surge volume over the normal level of collected liquid.

Influence of shape. The four major components of a separator are located differently in the variously shaped vessels. For example, in a vertical separator the primary section would be located about the middle of the vessel. In the horizontal vessel it would be located at the inlet end of the cylinder. In the sphere it could be located in the middle or in the upper portion of the vessel.

The vertical separator usually will use the full unrestricted diameter of the vessel for the gravity settling section. The horizontal separator of single barrel design will have available a minimum of one-half of the chamber, since the lower half will contain liquid. This section can contain straightening vanes. The double barrel horizontal separator has available the full volume of the upper chamber and most designs do utilize straightening vanes. The sphere uses the unrestricted interior of the large belly section in most designs.

The mist extraction section normally is in the extreme top of the vertical and spherical separator. In both horizontal types, the mist extractor is toward the opposite end of the vessel from the inlet.

The liquid collection sump is located in the bottom of the spherical and vertical separator. In the single barrel horizontal, the sump is in the lower one-third to one-half of the cylinder. The double barrel horizontal separa-



Double Barrel Horizontal Separator

FIGURE 3

tor utilizes from one-half to the whole of the lower cylinder, depending on requirements and design.

Regardless of shape, the best separator designs incorporate the four required separator parts into the vessel shell in the least complicated manner. Simplicity of interior design—the fewer internals and baffles used (without limiting capacity requirements)—will result in a separator that is easier to operate and maintain.

ADVANTAGES AND DISADVANTAGES

Each shape or type of separator has advantages and disadvantages, depending on use and particular design features.

Vertical. This separator has a definite advantage when well streams containing large quantities of mud and sand are to be processed. This is because the vessel has good bottom drain and clean-out features. It can handle more oil per unit of gas than any other type of standard design. The standard 10-foot shell length vessel has good surge handling ability. Since a vertical controller float can be used at all times, liquid level control is not critical. Because liquid level can be varied moderately to accommodate surging conditions, the vertical vessel is extremely useful on wells producing by gas lift or those which "head" large amounts of liquid. The vertical shaped vessel is a good space saver where installation area is limited, but it is difficult to mount on a skid that can be easily transported by truck. This is due primarily to its excess height.

The vertical unit will handle less gas per dollar than some other types, therefore it cannot compare economically with the horizontal, for example, on installations where its function would be primarily the separation of large volumes of gas. In shorter lengths it can be skid mounted readily for easy transportation, but does not usually compare in liquid or gas capacity per dollar with the spherical separator.

An additional disadvantage of the vertical is height, which makes top mounting safety devices difficult to reach and service. The gas outlet, also being at the top, makes the separator more difficult to install and hook-up than the other types.

Horizontal. Both types of horizontal separators are more economical for processing large volumes of gas than the other shapes. As an example, a single barrel horizontal separator with only half of the cylinder available for gas separation space, will have a larger gas capacity than the same shell size vertical separator. This is because the liquid droplets fall at 90 degrees to the flowing gas stream and have a relatively short distance to fall before they impinge on either the liquid surface or a straightening vane.

The double barrel separator, with the upper cylinder completely free for gas separation, would have even more gas capacity for the same size shell diameter, due to a lower gas velocity.

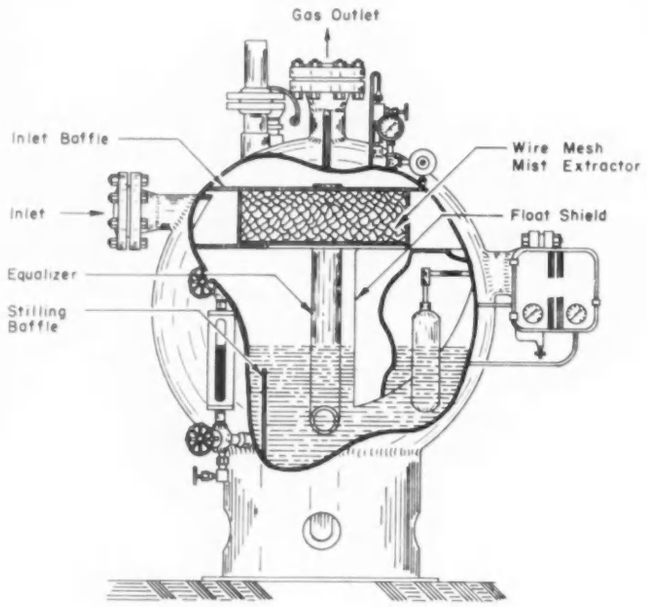
In a vertical separator, although gas velocity would be low due to flow through a full diameter section, separation capacity would be less because the liquid particles have to fall directly against the flowing stream.

The horizontal separator lends itself to skid mounting because of its low profile. It is relatively easy to install, and any portion of the separator can be reached while standing on the ground (an exception to this would be the 4-foot diameter or larger shell sizes).

Either type horizontal separator has a disadvantage when handling well streams that contain sand or mud. They have no natural sump for a good bottom drain, and no natural course through which sediments can flow out of the vessel. Consequently, sand accumulates in the cylinder and will soon block or hinder liquid and gas flow. For the same reasons, the horizontal separator is very difficult to wash clean.

When installation in compact areas is required, the horizontal separator is not too suitable unless "stacked."

In colder climates, the single barrel horizontal has a definite advantage when processing gas streams that con-



Spherical Separator

FIGURE 4

tain little liquid. The warmer gas flowing across the large gas-liquid interface in the separator will keep the liquid warm and above hydrate temperature. The single barrel horizontal separator with its large gas liquid interface has been more successfully used in handling foaming crudes than any other type. The large gas-liquid interface in most of these foaming separators is extended by internal foam-breaking baffles of various designs.

The double barrel horizontal unit can be designed to handle slugs and surges better than the single barrel.

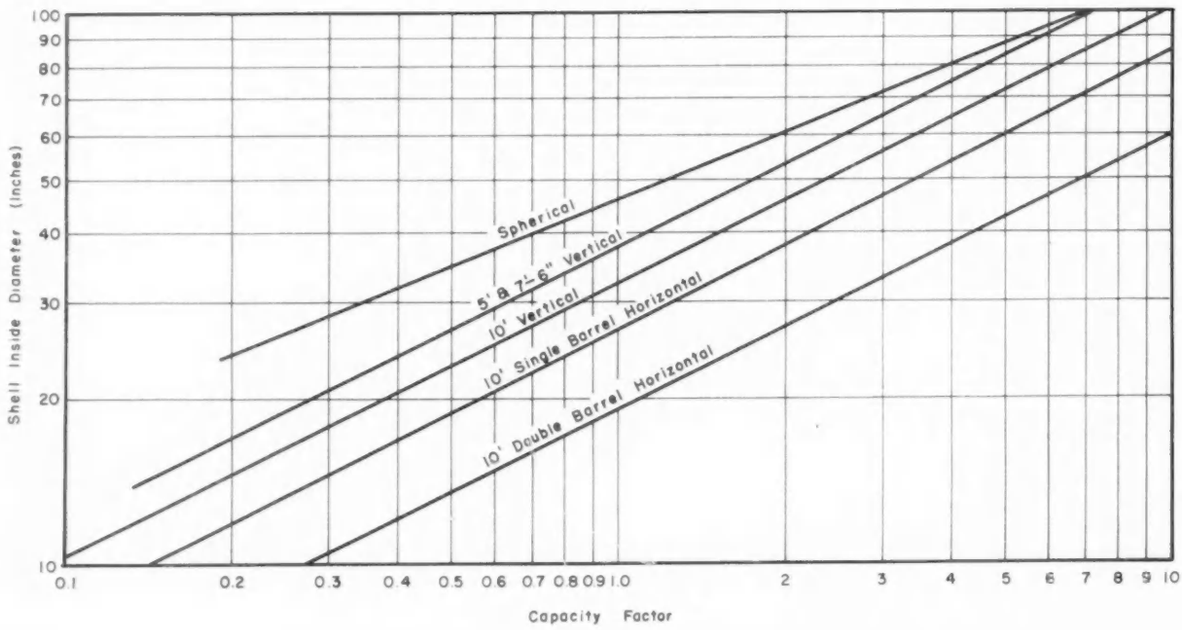
Spherical. The spherical separator is perhaps most used for its compactness. It is easy to skid mount and can be stacked one upon another so that two spherical vessels can be placed in the same area that one vertical separator would occupy. Properly sized, the sphere has excellent gas separation capacity per dollar and good liquid handling capacity. The clean-out and bottom drain features are better than the vertical separator. It is, however, not as economical for larger gas capacities as the horizontal separator, and surge capacity is limited. The size ranges available in the spherical separator make it the most economical type for high pressure, single well installations.

The sphere is suited to skid mounted portable test units. When not skid mounted, its advantageous handling, transporting and hook-up features make it useful for testing new wells when rapid installation is required. In the Gulf Coast area, where vessels are skid-mounted and/or stacked for easy portability, handling and mounting on water location platforms, the sphere is without equal. A packaged unit containing spherical vessels will use a smaller skid than horizontal units and will provide more room for operation and maintenance. Such a package need not be disassembled for shipment as would a unit of vertical vessels.

GAS CAPACITY

Figures 5, 6, 7 and 8 are used to correlate the gas capacity per day of the various size and shape vessels with pressure. Since gas capacity is a function of velocity, the capacity of any given vessel will vary with pressure. The lower the pressure for any given standard rate of flow the higher the velocity, and as velocity increases resident time decreases. Consequently, the gas capacity of a vessel will decrease with pressure.

Separator capacity factor for vessels of known inside diameter can be determined from Figure 5. Capacity fac-



Capacity Factor vs Shell
Inside Diameter For Separators

FIGURE 5

tor is a function of cross-sectional flow area, length and an imperical constant that takes into consideration the direction of particle settling with respect to flow direction, and mist eliminator effect. Although differences in internal design can vary the capacity factor, values given in Figure 5 will yield results that are accurate enough for most applications.

Only cylindrical horizontal separators of 10-foot shell length were considered in Figure 5. Conversion factors for other lengths may be found in Figure 7. Capacity factors for single barrel horizontal separators were calculated on the assumption that one-half of the cross-sectional flow area was available as gas separation space. Consequently, factors for single barrel horizontal vessels will be about one-half those for double barrel horizontals which were assumed to use the full cross-sectional flow area. Also, curves in Figure 5 cannot be extrapolated or interpolated to determine factors for intermediate sized vessels.

Normally, nominal pipe size designations are used to describe cylindrical vessels up to 30-inches in diameter. This happens to be outside diameter above 14-inches. Above 30-inches, where shells cannot be made of seamless pipe and must be rolled, the shell size designation can be *either inside or outside* diameter, depending on capacity requirements. However, even here the usual designation used for standard stock separators refers to outside diameter. Spherical vessel size designation refers to inside diameter almost universally.

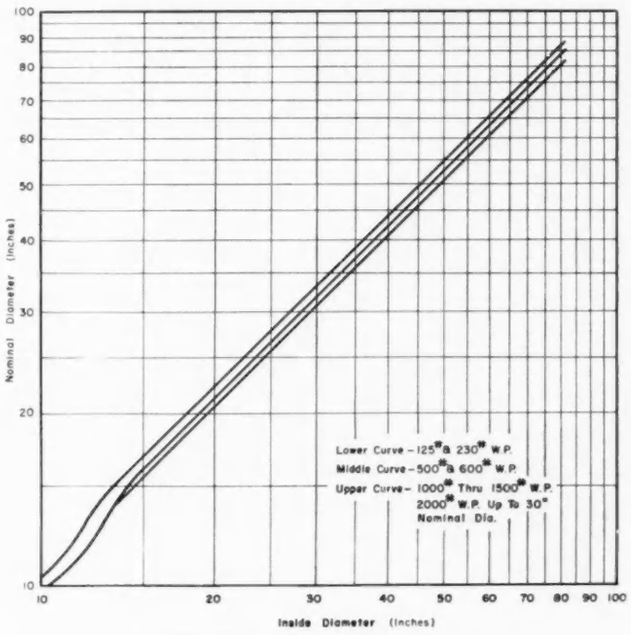
Figure 6 may be used to determine an approximation of inside diameter of cylindrical vessels of normal construction when nominal diameter is known. It is assumed that vessels up to 30-inches diameter follow nominal pipe sizing. For sizes 36-inch and above it is assumed that the normal designation refers to outside diameter. *Figure 6 should be used only if true inside diameter is unknown.*

Figure 8 may be used to determine the amount of gas per day that a vessel of any given capacity factor can handle at a given separator pressure. This graph is based on the following assumptions:

1. Gas is 0.65 specific gravity.
2. Oil particles in gas stream are 45° API, 10 microns or larger.
3. Main body of separated liquid is 35° API.
4. Operating temperature of 60° F, assuming this is above the cloud point of the oil and the hydrate point of the gas.
5. No excessive oil foaming or surging condition exists.

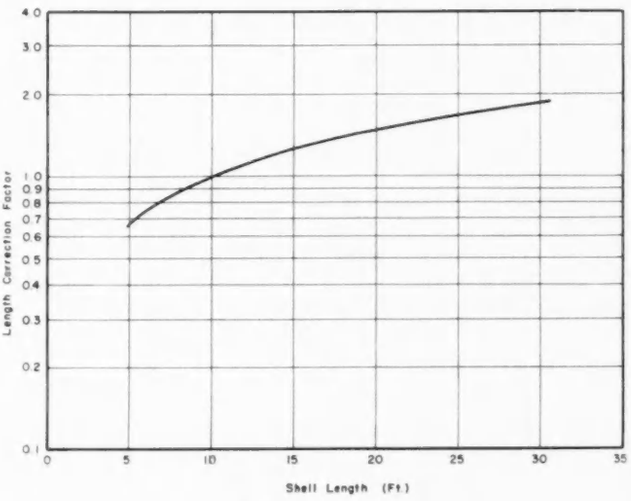
Figures 10 and 11 include capacity factor corrections for gas and liquid gravity, respectively. These correction factors are applied in the capacity factor in the same manner as the length corrections found in Figure 7.

Horizontal separator. To determine horizontal separator gas capacity, it is assumed that the vessel inside diameter is known and whether or not it is single or double barrel. The capacity factor is determined from Figure 5.


Nominal Diameter (Inches)
Inside Diameter (Inches)
Lower Curve - 125# @ 230# W.P.
Middle Curve - 500# @ 600# W.P.
Upper Curve - 1000# Thru 1500# W.P.
2000# W.P. Up To 30" Nominal Dia.

Approximate Inside Diameter vs Nominal Diameter For Cylindrical Separators Of Various Working Pressures

FIGURE 6



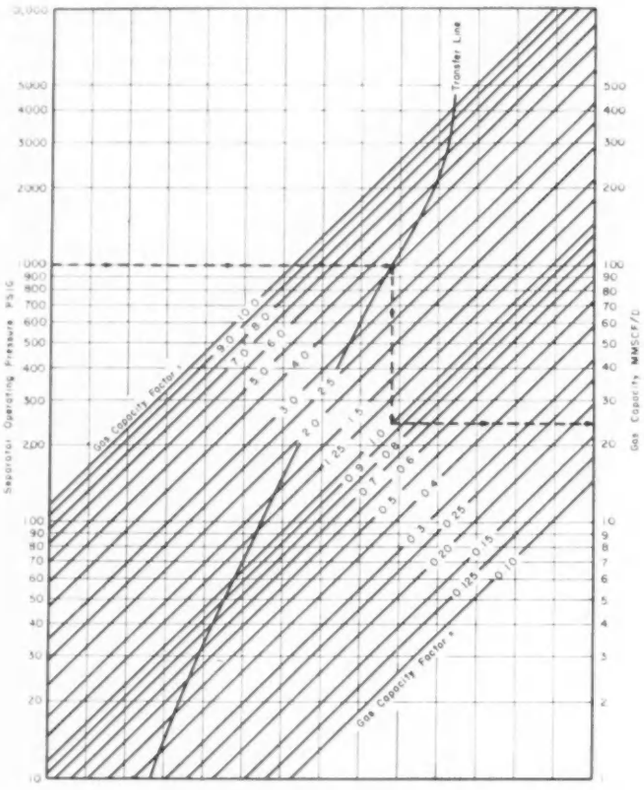
Capacity Factor Correction For Length Of Horizontal Separators

FIGURE 7

If the separator is a vessel of 10-foot shell length, gas capacity at any pressure can be found from Figure 8.

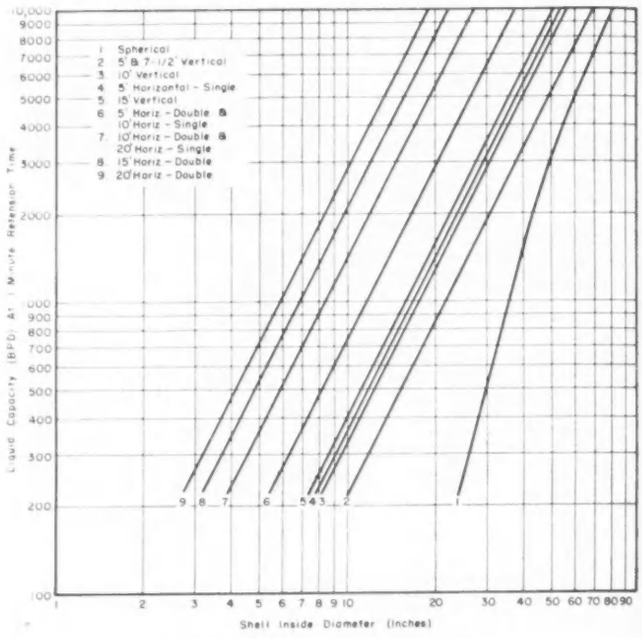
Should the shell length be other than 10 feet, the capacity factor can be corrected for vessel length by applying the length correction factor for horizontal separators found in Figure 7. In a like manner, if gas or liquid gravity differs from that used as the basis for Figure 8, a capacity factor correction for gravity is applied from Figures 10 and 11. After correction, gas capacity again is found from Figure 8. If only nominal shell diameter is known, the approximate inside diameter can be found from Figure 6 and the procedure is repeated as before.

Vertical separator. Vertical separator gas capacity is found the same way as the horizontal. As before, inside



Gas Capacity vs Pressure And
Capacity Factor For Separators

FIGURE 8


1 Spherical
2 5' & 7-1/2' Vertical
3 10' Vertical
4 5' Horizontal - Single
5 15' Vertical
6 5' Horiz - Double &
10' Horiz - Single
7 10' Horiz - Double &
20' Horiz - Single
8 15' Horiz - Double
9 20' Horiz - Double
Liquid Capacity (BPD) At 1 Minute Retension Time
Shell Inside Diameter (Inches)

Liquid Capacity vs Shell Inside Diameter
For Various Separators
(Basis: 1-Minute Retention Time)

FIGURE 9

diameter or estimated inside diameter is used to find the basic capacity factor. However, the procedure for adjusting capacity for length is somewhat different. Vertical separator gas capacity factor variation with length is shown in Figure 5.

Once a degree of liquid particle separation has been reached in a vertical separator, an additional increase in length above 10 feet will yield only a negligible increase in capacity. This effect is considerably less than in the horizontal separator, and is due to the particles falling directly opposite to the gas flow. The liquid thus has a much greater distance to fall before impinging against the liquid surface, vessel wall or other droplet collector.

As vessel length increases, the length of fall increases. Conversely, a minimum length of gravity settling chamber is required between the separator inlet and the base of the mist extractor for good vertical separation. Ten-foot verticals have this required length to prevent undue re-entrainment and mist eliminator overloading. Vertical units in the 5-foot to 7½-foot range require lower velocities, and consequently lower capacities, to prevent re-entrainment.

Vertical separators of standard manufacture with a 10-foot or longer shell have good built-in surge handling abilities. The distances between the vessel inlet, the normal liquid level and the base of the mist extractor are sufficient to accommodate fairly large rises in level due to surging conditions.

The 7½-foot and smaller verticals do not have this feature. When vessels of this size are used on production applications where surging can occur (other than on a single steady flow well or as an inlet scrubber), it is suggested that the gas capacity be rated at 75 percent of the amount calculated from the charts.

Spherical separator. The gas capacity factor for spherical separators is read directly from Figure 5 since size designation refers to inside diameter.

As in the case of the shorter vertical separators, it is suggested that the gas capacity of a spherical vessel be downrated in cases involving surging conditions. A factor of 75 percent is safe for most applications.

LIQUID CAPACITY

If foaming oil is not involved, a vessel's liquid capacity is restricted only by outlet or dump valve size and the pressure difference available for liquid discharge. Even without foaming, some bubbles of gas would leave the vessel entrained with liquid if the liquid was allowed to leave the vessel immediately after separation. To prevent this, separators are designed to hold or retain liquid a given length of time to allow the gas bubbles to evolve and return to the main gas stream. A separator's liquid capacity is determined by the volume in the vessel devoted to holding the liquid and the time it is held.

The retention time most generally used is one minute. If a vessel had a normal liquid volume of one barrel between the controlled level and oil outlet nozzle, liquid

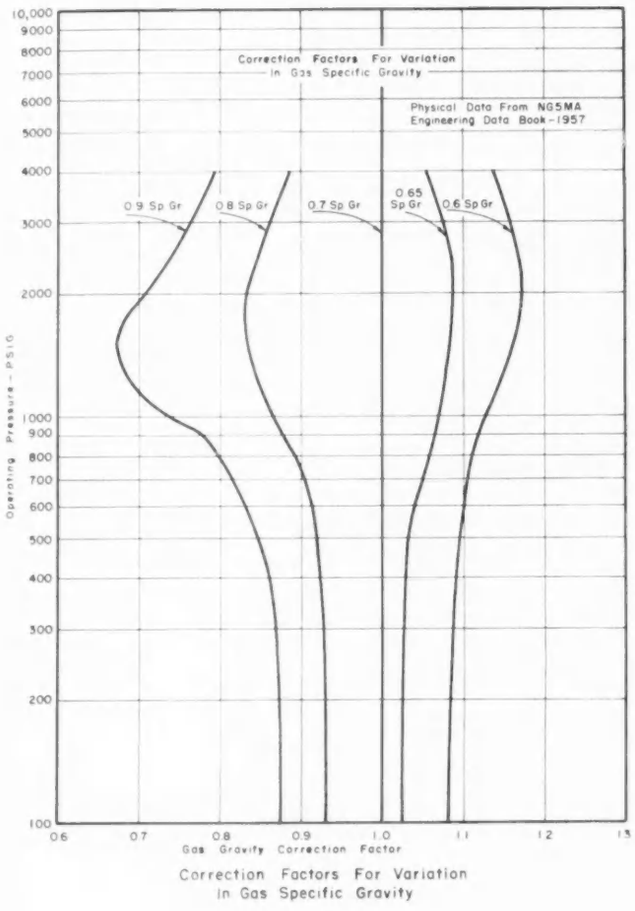


FIGURE 10

capacity would be one barrel per minute or 1,440 barrels per day for a one minute retention time.

If an abnormal gas-in-liquid entrainment occurred (a slight foaming condition) and a two-minute retention time was necessary to allow the gas to break out, the vessel's capacity would be one-half as much or 720 barrels per day. However, unless otherwise specified the vessel normally would be rated at a one minute retention time.

A condition that can make sizing for liquid complicated is one in which extreme slugging or surging conditions occur. This condition is brought on by an abrupt increase in liquid to gas ratio. A point can be reached when liquid streams or slugs of some quantity enter the vessel instantaneously with no gas present.

When this condition is reached and the volume of liquid entering is more than the fully open dump valve can handle at the operating pressure, the liquid level will rise and push gas from the vessel. If insufficient volume is available in the vessel, liquid will eventually reach the gas outlet and carry-over into the gas line.

It is not necessary for the vessel to completely fill for carry-over to occur. Carry-over will take place when the level is high enough to restrict the gas separation portion of the vessel. When gas again begins flowing into the vessel, its velocity can be such that proper separation cannot take place in the remaining vessel volume. This condition can be aggravated by the re-entrainment of some of the liquid already in the vessel.

Sizing for this difficult condition is of necessity a balance between vessel size and dump valve size and number. It is necessary to estimate the maximum size and frequency (flow rate) of the liquid slugs. The allowable level variation in "X" vessel and the allowable capacity of the dump valve or valves that will prevent the level from exceeding the maximum level then can be determined.

Extreme slugging may be expected under the following conditions:

- On a large diameter gathering line into which liquid is being produced with gas or in which liquid condensation can take place due to temperature decreases.
- At a juncture in a large trunk and lateral gathering system with the possibility of intermittent flowing of wells on the laterals.
- On a lease where a large number of wells are being produced by intermittent gas lift or where wells are known to flow with a heading characteristic.

When slugging conditions exist, it also is a good idea to consider decreasing a vessel's gas rating. (See section on Gas Capacity.) The decrease can be arbitrary, but a factor of 75 percent of standard usually is adequate assuming that the normal liquid level is not allowed to vary excessively through use of valves properly sized to handle the rated liquid capacity.

Figure 9 gives the liquid capacity of the various size and shape vessels. All capacities are based on a one minute retention time, on inside diameter and a reasonable liquid level above the oil outlet nozzle.

Spherical. Curve 1 in Figure 9 can be used to determine liquid capacity of a spherical separator when shell diameter is known. In plotting Curve 1, it was assumed that the normal liquid level was below and not closer than five inches from the vessel center line.

Because of its geometry, liquid surface diameter will increase as liquid level rises in the lower half of a spherical vessel. Thus, spheres exhibit good surge volume at the vessel center line. For instance, in a 24-inch sphere, a 5-inch rise in level at the vessel center line is equivalent to a volume of about ¼ barrel. This is nearly 60 percent more volume than the vessel contains for liquid retention from the normal level to the liquid outlet. Therefore, with spherical design a larger percentage of volume is dedicated to surging than to retention.

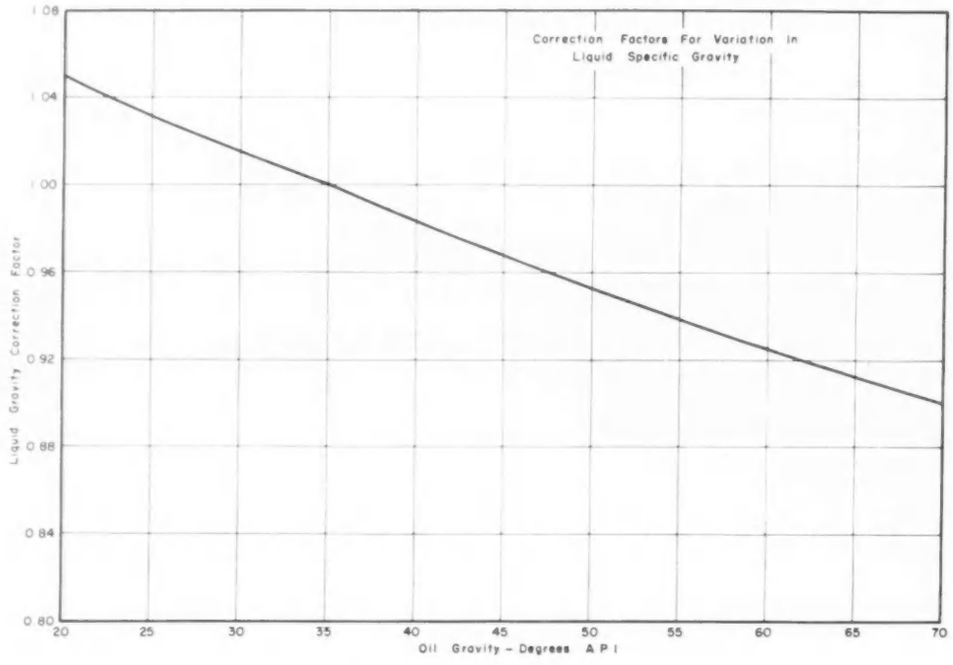
When a 24-inch sphere is compared with the 16-inch x 5-foot vertical vessel which contains nearly the same total volume but has less gas capacity, it is found that a 5-inch rise in level in the 16-inch x 5-foot vertical is about a tenth of a barrel, or less than one-half that in the 24-inch sphere.

As in all separator applications, however, care should be taken when sizing spheres for surging flow conditions.

Vertical. Vertical separator capacities shown in Figure 9 are based on the following liquid levels above the oil outlet:

Shell Length, Feet	Level, Feet
5 and 7.5	1.50
10	2.25
15	2.75

As indicated previously, surge capacity is not determined by the volume held below the normal liquid level, but by



Correction Factors For Variation
In Liquid Specific Gravity

FIGURE 11

the volume above the normal level and the allowable level rise before gas capacity and amount of carry-over is affected.

Since standard 10 foot and taller verticals generally allow more than half of the available volume for liquid collection, they are well suited to surging conditions.

Horizontal single barrel. Data for single barrel horizontal separators presented in Figure 9 are based on the assumption that one-half of the vessel is used as liquid retention volume with the normal level at the center line of the vessel. It is evident that in vessels of large diameter, vertical floats can be used to give excellent level control variation. In such designs, the level may be lowered easily (reducing the retention volume) to accommodate heading flow.

Because of the large liquid surface area and ample space for installation of foam-breaking baffles, the single barrel horizontal separator is the most effective shape for handling foamy crude.

In Figure 9, liquid capacity for horizontal separators is directly proportional to length (capacity of 10-foot single barrel horizontal is twice that of 5-foot single barrel horizontal).

Horizontal double barrel. Liquid capacities of double barrel separators shown in Figure 9 were based on the assumption that a lower cylinder of the same size as the upper was used and that this cylinder would be substantially full of liquid at normal level. It is obvious that the lower cylinder can be either larger or smaller than the upper, depending on the liquid retention time required. Most standard designs utilize a lower cylinder either the same size or smaller than the upper.

Double barrel separators offer much design flexibility in regard to either gas or liquid capacity. By controlling down-comer size and lower cylinder volume, extremely large surging flows can be handled more effectively than with any other type. Standard designs afford moderate surge protection.

SEPARATOR SELECTION

The following procedure may be used when selecting a separator for a particular application:

- Find one each of the various size and shape vessels that fits gas and liquid requirements. Both present and future operating conditions should be considered.
- Compare costs.
- Determine which shape fits the particular installation best—space, mounting, ease of access and external maintenance should be considered.
- Determine whether over-all cost is affected by the installation or portability of the shape selected.
- Determine whether unusual well stream conditions (foam, sand, etc.) would make the vessel selected difficult to operate or maintain.
- Make certain that there is no design requirement (heating coils for paraffin or hydrates, three phasing for water removal, etc.) that would make the shape selected expensive to use or difficult to operate.

This selection method is an excellent rule-of-thumb which takes into account most foreseeable operating conditions. On many occasions, a closely engineered evaluation will show that the separator with the lower first cost is not always the most economic selection.

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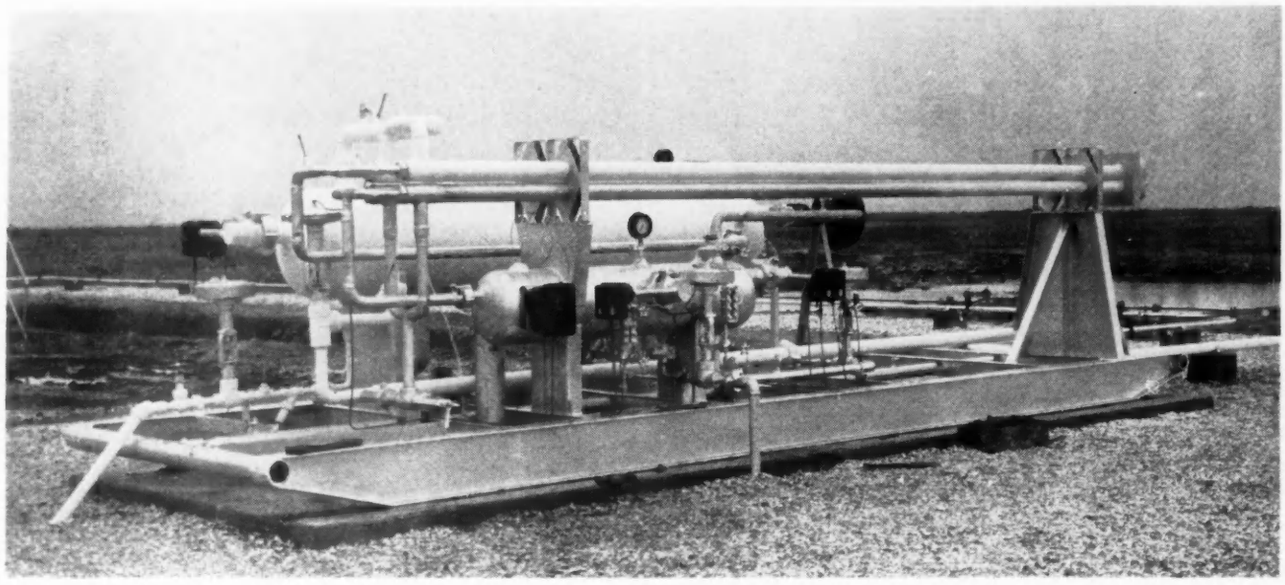

Horizontal free liquid knockout, horizontal low temperature separator.

2. THE LOW TEMPERATURE SEPARATION UNIT

By George J. Mapes
Product Application Specialist
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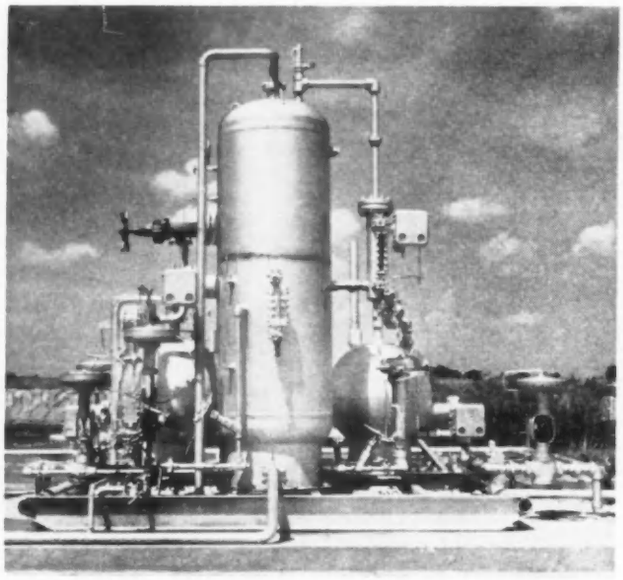
The low temperature separation (LTS) unit consists of five basic components:

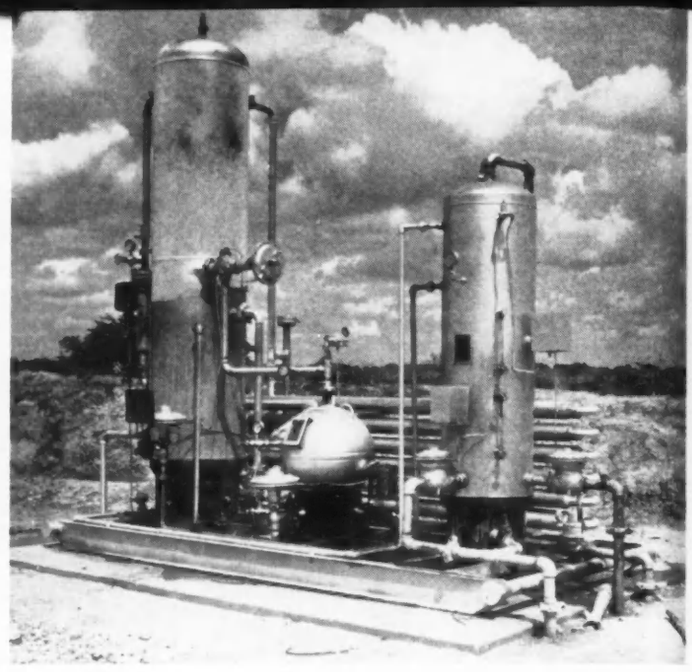
1. The low temperature separator
2. The free liquid knockout
3. The heat exchanger
4. The choke
5. The flash or second stage separator (optional equipment).

Adequate piping, valving, etc., are required to complete the unit. In addition, line heaters often are used upstream of the LTS unit to heat the input gas stream. A flow diagram for a typical conventional low temperature separation installation is shown in Figure 1.

The LTS unit also may be used in conjunction with accessory equipment. For example, Figure 8 shows an LTS system equipped with a stabilizer and a glycol injection system for hydrate protection. Figure 9 shows an LTS unit which has been adapted for use with a steam generator. Although these units may appear in different

Twin vertical free liquid knockouts, combination vertical-horizontal low temperature separator, vertical flash separator.





Here are several different types of low temperature separation units. Note the various

physical forms, it should be kept in mind that all operate on the same basic principle.

Producers utilize low temperature separation on high pressure gas wells where pressure drops of approximately 1,000 psi (sometimes less) above sales line pressure are available to produce separation temperature in the range of 30° F and lower.

This low separation temperature provides a lower sales gas water dewpoint and more condensate recovery. Increased condensate recovery results in quick payout of equipment and increased revenue, making low temperature separation equipment attractive when reservoir pressure is expected to hold for a sufficient length of time to justify cost of the unit, usually 3-5 years or longer.

THE LOW TEMPERATURE SEPARATOR

The heart of a low temperature separation unit is the low temperature separator, which appears in four basic forms: horizontal, vertical, spherical and T-bone, a combination vertical-horizontal. Schematic drawings of each type vessel are shown in Figures 2, 3, 4 and 5.

The upper portion of the LTS vessel is the cold section, into which the high pressure wellsteram gas is expanded through a choke. This produces low temperature condensation of water and hydrocarbon components. As this condensate and water fall toward the lower or liquid section of the vessel, hydrates are formed which collect in the liquid section.

Wellstream gas, or steam in some cases, warms a coil which is submerged or partly submerged in the liquid section (see schematic drawings of separator vessels). Heat from this warm coil melts the accumulated hydrates. The warm coil must contain sufficient surface area to effect partial stabilization of the liquid, an important secondary function. Revaporizing the light ends, principally methane and ethane and lesser amounts of butane and propane, which rejoin the sales gas, leaves a more stable liquid which undergoes less shrinkage when discharged to atmospheric storage.

In some cases, less coil area can be counteracted by heating the gas stream to a higher temperature to maintain a greater log mean temperature difference between the coil and the liquid. However, if this is done the tube bundle heat exchanger must be adequate to handle the higher temperature gas from the coil.

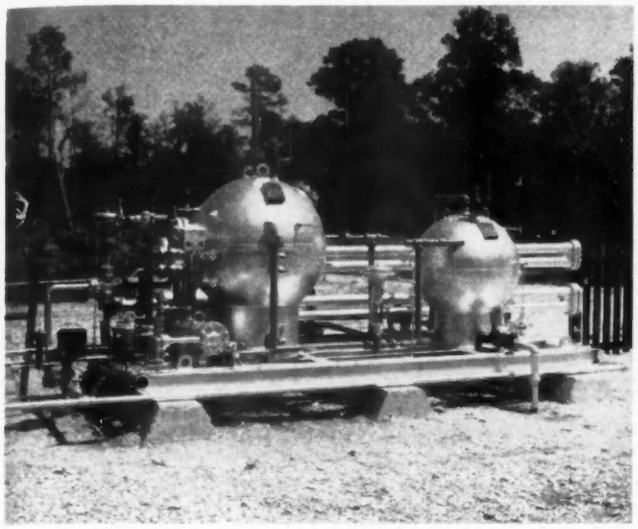
The lower the temperature of the gas after expansion to a given pressure, the more water and distillate will be condensed from the stream. Therefore, semi-isolation of this cold section from the warm liquid section results in very low gas separation temperatures. The additional water condensed from the gas stream at the lower temperature will settle below the blanket of distillate and be drawn off the vessel through the water discharge valve before sufficient warming occurs to resaturate the cold gas with water vapor. Therefore, colder separation may result in drier sales gas.

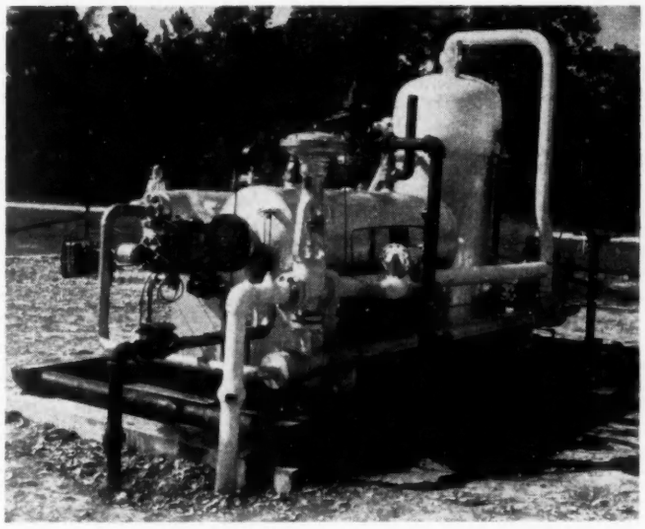
The LTS usually is equipped to separate the water and condensate and discharge them separately, however, there may be occasions where water-oil separation is not provided for.

A parallel may be drawn between colder separation resulting in drier sales gas and distillate separation at the colder temperature, where more distillate condenses from the stream in the proportion of the equilibrium ratios of the components. Also, revaporization of the distillate components takes place in the warm section of the LTS, in proportion to their equilibrium ratios at the given temperature (90° F) and operating pressure.

When a natural cold reflux action exists between the rising warmed gases liberated from the liquid phase and cold condensed liquid falling from the stream inlet, the lighter ends rejoin the departing gas stream and the heavier components recondense and are drawn from the vessel as a stable stock tank product.

To summarize, (1) a colder separation temperature removes more liquid from the gas stream; (2) adequate bottom heating melts the hydrates and revaporizes the lighter components so they may rejoin the sales gas instead of remaining in liquid form to be flashed off at low pressure; (3) cold refluxing recondenses the heavy com-





combinations of low temperature separators, free liquid knockouts and flash vessels.

ponents which may also have been vaporized in the warming process and provides stable liquid recovery.

THE LIQUID KNOCKOUT

The liquid knockout which usually operates between 2,000 and 6,000 psi, performs an important function in removing free water and hydrocarbon condensate from the inlet gas stream. This free water otherwise would freeze in the choke of the low temperature separator as the expanding gas drops the temperature below the hydrate point. Liquid hydrocarbons passing the choke do not contribute to the adiabatic expansion and only give up heat, decreasing the net refrigeration effect of the expanding gas.

The horizontal knockout has a large liquid and gas capacity under steady flow conditions. The vertical knockout has a considerable liquid surge capacity and mud is easily removed from the vertical vessel. Also, "double barrel" versions of horizontal and vertical knockouts are available. The spherical knockout is attractive economically.

THE HEAT EXCHANGER

The tube bundle, gas-to-gas heat exchanger performs an important dual function in the standard cold separation process.

The warm inlet gas stream may enter the coil submerged in the LTS liquid section (described previously) at 120° F or higher. In passing through the coil and melting the hydrates in the separator, the gas temperature may drop to 100°-110° F. However, it is necessary to lower the temperature of the stream still more to approximately 80° F, or the lowest safe point above the hydrate temperatures at the pressure upstream of the choke. This will insure maximum recovery of free liquid in the knockout, and will provide the lowest separation temperature in the LTS with the pressure drop available.

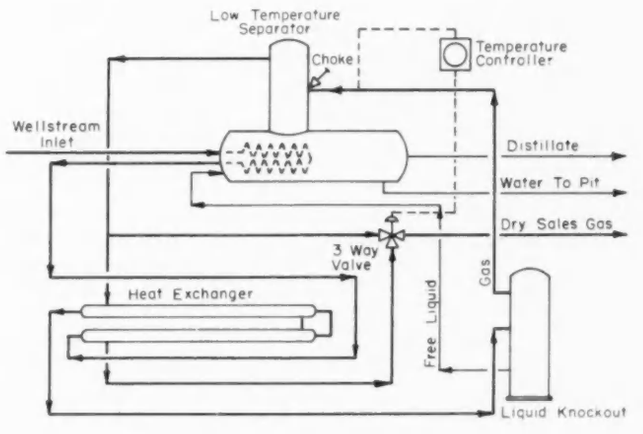
The well stream to be processed flows from the coil in the liquid section of the LTS through the tubes in the heat exchanger where it is cooled by 30° F and colder sales gas from the LTS. This dehydrated, cold gas counter flows through the shell prior to entering the sales line. The sales gas thus is warmed before entering the sales line, minimizing the possibility of chilling other "wet" gas in the sales line to the hydrate point.

A temperature controlled three-way bypass valve is placed at the heat exchanger to maintain the lowest safe temperature above the hydrate point upstream of the choke. With this controller, the cold gas may be proportioned through the heat exchanger automatically. Figure 6 shows a typical heat exchanger.

THE CHOKE

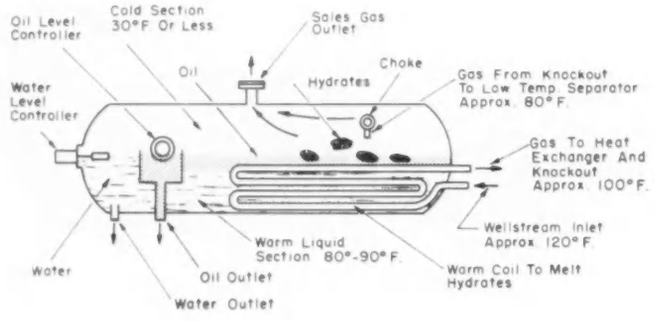
If the pressure in the low temperature separator is to be controlled by the back pressure in the downstream gas line or by a back pressure regulator, an adjustable choke may be used on the inlet to the low temperature separator to regulate the gas flow.

A regulating choke at the separator inlet may be used either as a pressure regulator or as an adjustable choke to control flow. When the regulating choke is used to con-



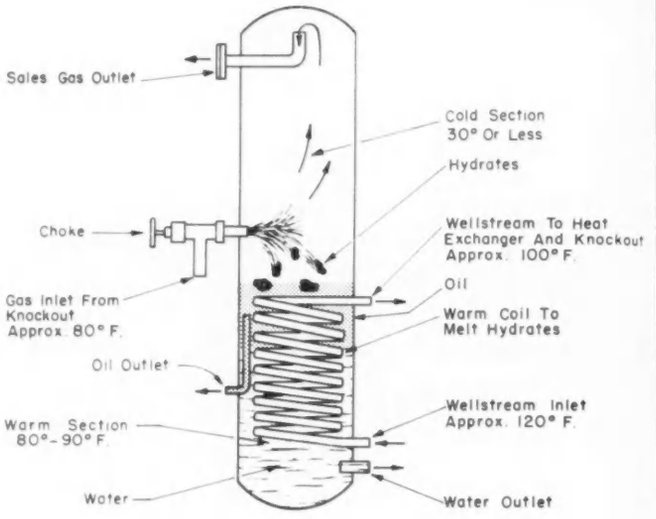
Flow Diagram Of Conventional Low Temperature Separation System

FIGURE 1



Schematic Diagram – Horizontal
Low Temperature Separator

FIGURE 2



Schematic Diagram – Vertical
Low Temperature Separator

FIGURE 3

trol pressure on the separator, an additional choke is needed on the sales line downstream of the unit to control flow (see section on Upstream Vessels and Piping).

It is also good practice to use a flare relief valve in parallel with the back pressure regulator on the sales line to protect vessels and piping in case high flow rates reduce the temperature sufficiently to freeze the back pressure regulator.

THE FLASH SEPARATOR

Liquid usually is piped from the knockout to the liquid section of the cold separator to undergo primary stabilization and three phase separation of water, distillate and gas. After primary stabilization at high pressure in the cold separator, a greater volume of stable stock tank liquid is retained if it is flashed through a second stage separator operating in the range of 100 to 125 psi.

The flash of the liquid at a calculated intermediate pressure between cold separation pressure and stock tank pressure, tends to reduce the loss of heavy hydrocarbons normally experienced when flashing the liquid from high pressure direct to the stock tank. The ideal situation would be an infinite number of small pressure reductions which are not economically practical.

Choice between either horizontal or a vertical second stage separator is usually a function of design for space arrangement, since there is little process preference except that a horizontal vessel of equal size offers greater interface area for gas release. However, this is a very minor point in connection with a flash chamber where gas release is principally the result of change of state rather than fluid demulsification. The spherical separator in second stage separation has a large gas release interface area, and can be considered as effective as the other two types.

UPSTREAM VESSELS AND PIPING

It is considered good practice to design vessels and piping upstream of the choke on the LTS to stand the full shut-in pressure of the well. Wellhead pressure could be applied to the upstream section of the unit if the LTS choke were to "freeze" or fail in the closed position. However, such practice is not always practical when dealing with abnormally pressured wells since the additional cost of high pressure piping, knockouts, fittings, coils, etc. would be prohibitive.

Abnormally pressured well streams (7,000-10,000 psi) may be reduced to the 3,500-6,000 psi range by a pressure regulator located near the line heater and upstream of the LTS unit. This would permit the lower pressure design to be incorporated into the unit piping and knockout upstream of the choke on the LTS. In such cases, a regulating choke could be used to advantage on the LTS.

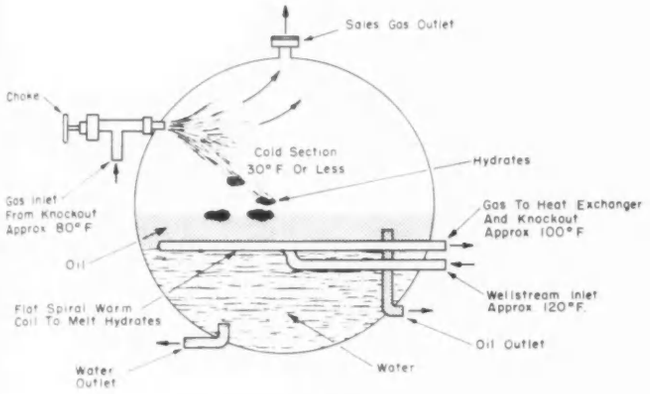
The pilot bourdon tube on the LTS regulating choke then could be connected into the piping upstream of the choke. This would allow the choke to automatically relieve excess pressure which might build to wellhead pressure on the upstream section of the unit should the choke freeze. A back pressure regulator then is used downstream of the separator.

Although a regulating choke will provide some measure of safety, when lower pressure designs are used upstream of the LTS choke, it is also good practice to include high-low shut off valves on the well for complete protection.

One method used to hookup abnormally pressured wells is shown in Figure 7. In this case an 8,000 psi well is shown tied into an LTS system.

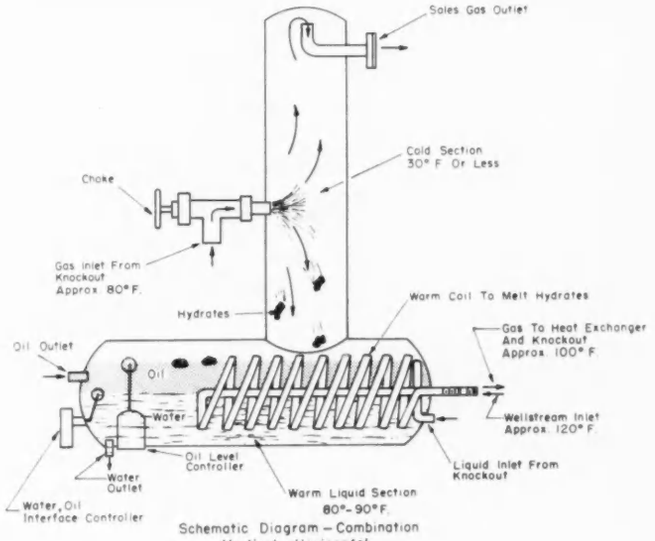
A high-low shut-off valve is installed on the christmas tree. The control line for the shut-off is tied into the flow line downstream of the pressure-reducing regulator at the heater. If an abnormally high pressure occurs downstream of the regulator on lower design pressure equipment because of regulator failure, or if the flow line fails at any point between the well and the unit, the well will automatically be closed in by the shut-off valve.

The regulator located downstream of the line heater is normally closed and is used to reduce wellstream pressure from 8,000 to 4,000 psi (liquid knockout working pressure). Thus, all equipment between the regulator and



Schematic Diagram—Spherical
Low Temperature Separator

FIGURE 4



Schematic Diagram—Combination
Vertical—Horizontal
Low Temperature Separator

FIGURE 5

the LTS choke operates at 4,000 psi. The by-pass around the regulator is required for start-up.

A high pressure valve is located at the LTS inlet, and is used to isolate the unit from the flow line. All piping and connections upstream of this valve are designed for wellhead pressure.

High-low shut-off valves also may be used to protect the low temperature separator. An additional control line is tied into the separator from the shut-off pilot. The well then is automatically closed-in if the sales gas line fails or if the pressure regulator on the sales gas line freezes and causes a pressure build-up on the LTS. In many cases, more than one shut-off valve is used for complete protection.

In normal applications where heat transfer conditions at the tube bundle heat exchanger are not critical, it is advantageous to place the liquid knockout downstream of the heat exchanger and immediately upstream of the choke. This permits removal of the additional free liquid condensed in the heat exchanger, and leaves the gas stream to the choke essentially void of all free liquid thus achieving the lowest possible expansion temperatures.

Abnormal applications, (a) where heat exchange area is critical as it usually is on extremely low pressure wells, or (b) where paraffin base oil must be removed before being further cooled, dictate that the knockout must be upstream of the heat exchanger. Actually, it would be advantageous to place one knockout upstream and another downstream of the heat exchanger, but this is seldom economically practical.

STABILIZATION COLUMN WITH PRODUCTS COOLER

On larger volume gas streams where fluid recovery exceeds 35-40 bpd, a products stabilizer used in lieu of the second stage separator usually will produce sufficient increased stable stock tank liquid to justify the somewhat larger investment of the stabilizer column, steam generator or other heat source and the products cooler (Figure 8).

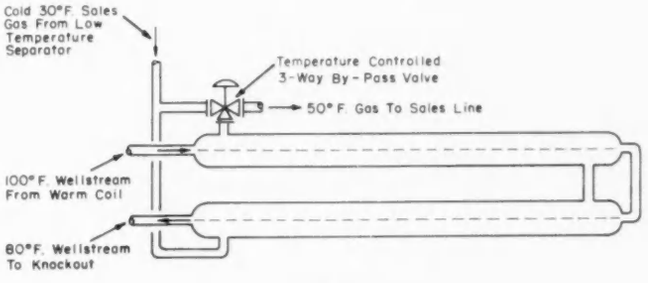
The stabilizer has the added advantage of producing a controlled vapor pressure product. Cold distillate feeds into the top section of the stabilizer column from the LTS and flows downward through a series of bubble trays or over ceramic packing. The heat coil in the stabilizer sump vaporizes the lighter components along with small amounts of heavier ones. Heavy hydrocarbons are recondensed from the vapors ascending through the descending cool liquid, and fall back into the stabilizer sump. The vapor pressure of the resultant product can be controlled by temperature adjustment in the stabilizer.

The heavy, stabilized liquid passes from the stabilizer through the product cooler to the stock tank. The product cooler is a tube-in-shell heat exchanger which may be cooled by circulating water or by the cool gas stream.

LINE HEATERS

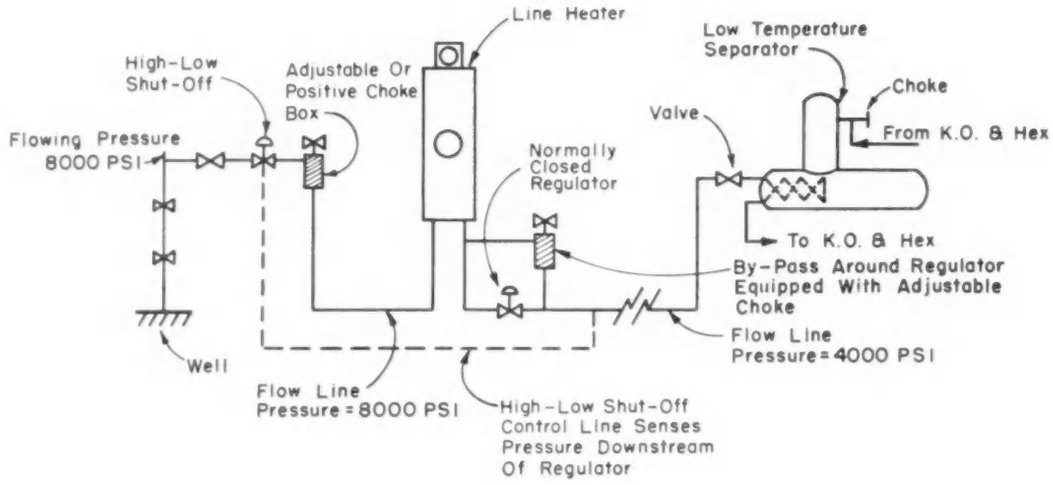
Although it is not considered part of the low temperature separation unit, a line heater usually is required at the well head to initiate flow from a high pressure well and to bring it up to capacity, since smaller volumes of gas are influenced considerably by ground cooling. Also, if a regulator is required to reduce wellstream pressure between the well and the unit, this restriction of flow may cause additional cooling to temperatures below the hydrate point for the pressures involved.

After the well reaches capacity, the heater often can be bypassed. However, in some cases it is advantageous to throttle the heater to maintain the inlet temperature of the gas to the LTS unit at 110°-120° F, since a tem-



Typical Heat Exchanger
Used On LTS Units

FIGURE 6



LTS Unit Hook-Up For
Abnormally Pressured Wells

FIGURE 7

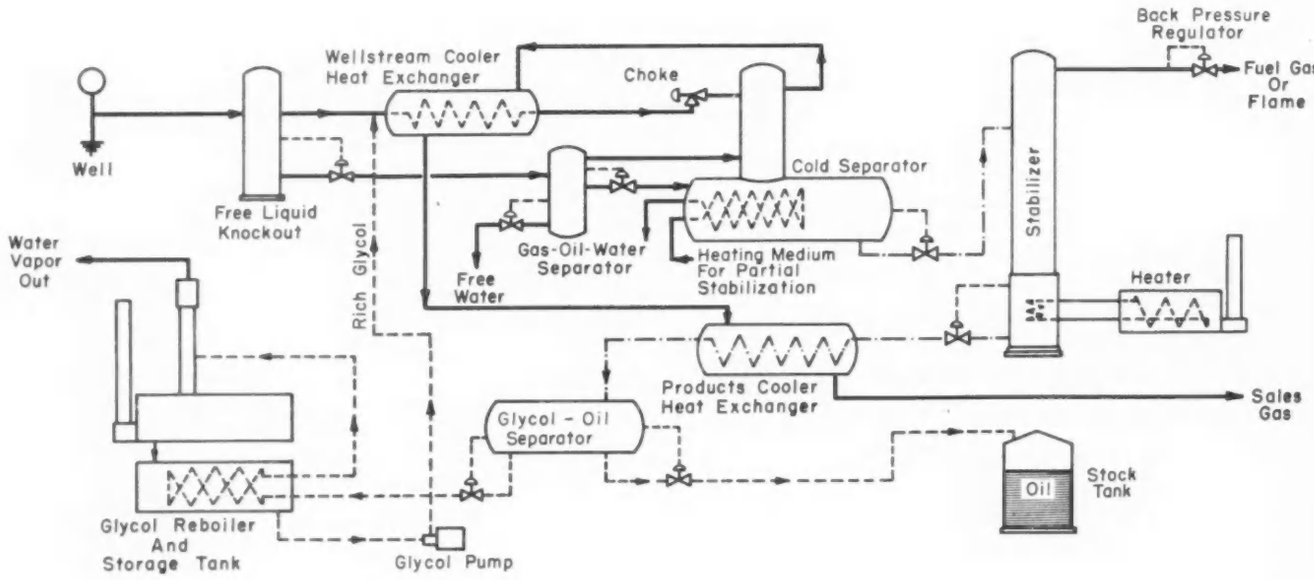
perature in this range is required in the heat exchange coil in the bottom of the low temperature separator.

When handling high pour point distillate, LTS units may be equipped with a secondary heat exchange coil in the bottom of the flash separator. This secondary coil keeps the distillate in the flash separator warmed above the pour point and allows it to be dumped to the stock tank without the danger of congealing, and possibly plugging the dump line. In such cases, it is often advantageous to increase the inlet gas temperature, by means of the line heater, above the 110°-120° value mentioned previously, since the inlet gas stream must heat both the liquid bath in the low temperature separator and the liquid contained in the second stage separator.

In cases where paraffin base oil is present, the liquid knockout is placed upstream of the heat exchanger to prevent the liquid from congealing and fouling the heat exchanger. Without these measures, it would often be necessary to steam deposited paraffin out of the heat exchanger.

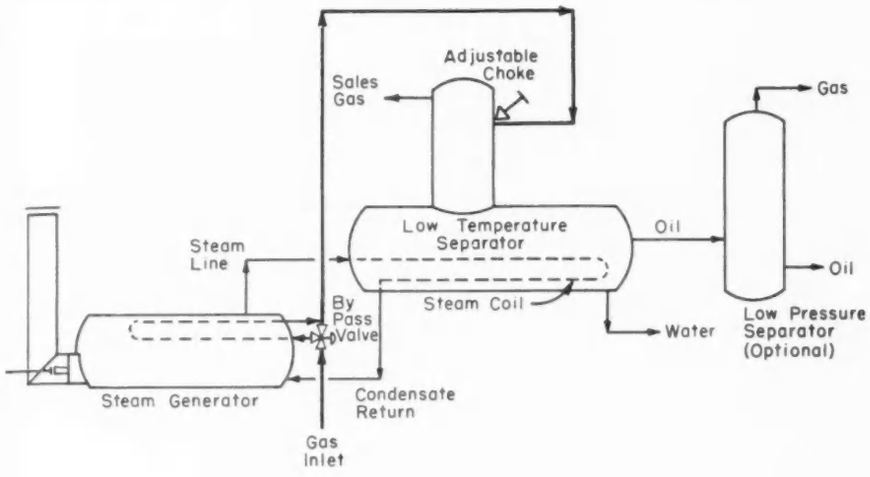
ANTI-FREEZE AGENTS

Often, a producer will prefer to inject an anti-freeze agent such as methanol into the gas stream at the wellhead to protect against hydrate formation during the start-up period. This procedure is frequently used offshore for two reasons: (1) it is not always convenient and often too costly (from the point of platform space) to provide



Flow Diagram Of LTS System Equipped With
Stabilizer And Glycol Injection System

FIGURE 8



Flow Diagram Of LTS Unit Equipped With Steam Generator

FIGURE 9

a heater to be used only for start-up and (2) there are times when heating will not be sufficient to maintain the temperature of the gas above the hydrate point during transmission by pipe line from the producing platform to a central dehydration plant onshore.

Hydrate protection by injection of an anti-freeze agent overcomes problems due to cooling during transmission. When cool gas in the range of 70°-80° F reaches the inlet to the low temperature separation unit, a variation in equipment is often appropriate (See Steam Generator Applications).

STEAM GENERATOR APPLICATIONS

When a "cold" gas stream, generally below 100° F, is to be fed to the low temperature separation unit, it is often advantageous to eliminate the high pressure heat exchange coil in the LTS liquid section since the inlet gas stream is too cool to adequately melt accumulated hydrates and vaporize the light ends. This coil is replaced by a low pressure (15 psi) steam coil fed by a steam generator (Figure 9).

Circulation through the low pressure steam coil and the steam generator depends upon thermo-syphoning and, as a rule-of-thumb, a liquid head of about 2 feet should be provided between the lowest point in the steam coil and the high water level in the steam generator. This may be done by elevating the LTS unit or installing the steam generator at a lower elevation.

Often, for start-up purposes and hydrate protection where the gas temperature is marginal for the pressure upstream of the choke, a short high-pressure heat exchange coil is placed in the hot water bath in the steam generator to warm the inlet gas stream.

When handling 'cold" flowing gas streams, the tube-bundle gas-to-gas heat exchanger may be reduced in size or eliminated altogether, since there is little or no cooling needed to maintain a low gas temperature as close to the hydrate point as is practical upstream of the choke.

HYDRATE RETARDING EQUIPMENT

When dealing with *high*-pressure gas condensate wells, the injection of an anti-freeze agent such as diethylene glycol can seldom be justified because of the expense of including additional necessary equipment on the LTS unit.

In such cases, the available pressure drop produces a separation temperature sufficient for the specified water dewpoint and the optimum hydrocarbon recovery, dependent upon the particular gas analysis and type product desired. At 1,000 psia, a 30° F separation temperature results in less than 7 pounds of water per MMscf of processed gas, whereas at 600 psia the separation temperature must be 18° F to produce 7 pounds water content.

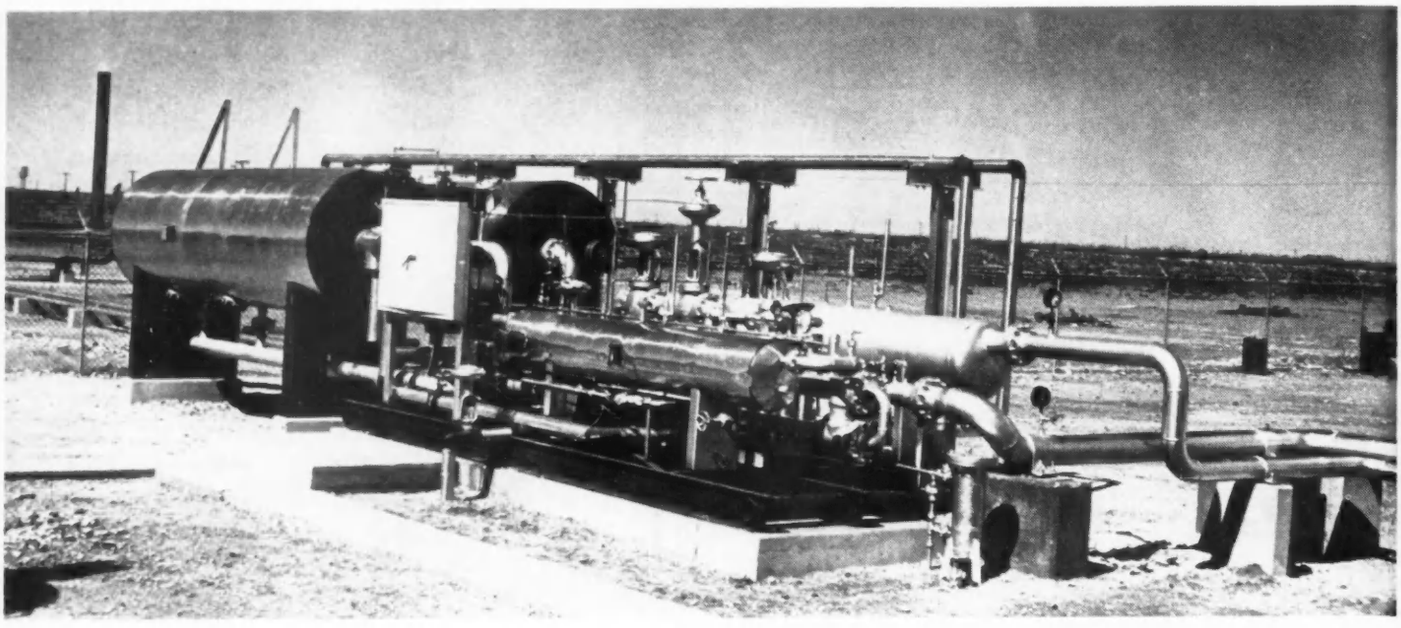
However, there are instances when glycol injection can be used to advantage on LTS units which serve high pressure gas condensate wells. If wellstream composition is such that lower separation temperatures in the range of 0° F to —20° F will provide additional hydrocarbon re-recovery, glycol injection is economically feasible. The additional recovery realized will payout the cost of the necessary anti-freeze injection equipment.

Considering a *low* pressure well flowing at 2,000 psia and 100° F, a 1,000 psi pressure drop reduces the separation temperature to about 57° F, and the water content to 16 pounds MMscf. Through use of a heat exchanger, the cold gas leaving the LTS may be used to cool the inlet gas to say 70° F. Now, the pressure drop provides a separation temperature of 27° F, adequate for less than 7 pounds water content. However, at 2,000 psia and 70° F, hydrates form to foul the lines.

Injection of the anti-freeze agent upstream of the heat exchanger will eliminate the formation of hydrates (see Figure 8). Lowering the inlet gas temperature more than 27° (See above) will result in recovery of more hydrocarbons, especially butanes and propanes. This, however, may be undesirable if there is no market for the LPG.

Usually, the glycol used as the hydrate retarding agent must be reclaimed to make the process economically practical. This equipment includes a glycol-oil separator, usually horizontal for greatest glycol-oil interfacing area, with sufficient volume for adequate settling time; a glycol regenerator to remove water from the glycol; and a glycol recirculating pump. (See Part 5, The Glycol Dehydrator.)

Each component of the low temperature separation unit is worthy of study from the process as well as the economic standpoint when selecting a unit to best satisfy the characteristics of a gas stream. Manufacturers now offer standard components which may be assembled into the type unit needed.



Two typical long cycle dry desiccant dehydrator installations. Unit in photo at left is equipped with

3. THE LONG CYCLE DRY DESICCANT DEHYDRATOR

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THE LONG CYCLE DRY DESICCANT dehydration unit is widely used as a means of drying natural gas in the field. Many producers have installed or are installing compressor and dehydration facilities on the lease to collect, dry and sell gas. Because of this trend, and the ability of the dry desiccant unit to provide low dew points the method has become of increasing interest to production personnel. New desiccants, improved equipment and automation have further stimulated interest, and increased acceptance of the technique.

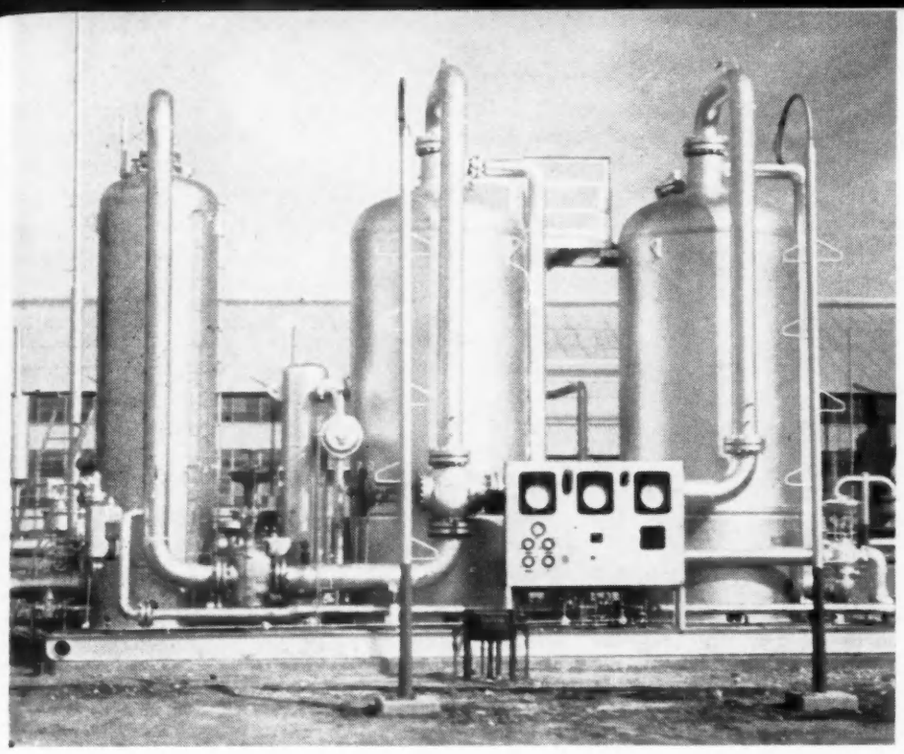
Early units were used at centralized collection points and consisted of multiple towers which were manually switched by the operator. These installations were designed on 8, 12 or 24 hour cycles; established partially by economics and partially by operating convenience. By adding time-cycle controllers and diaphragm motor valves, the unit became automatic. With automation, time cycles as short as 2-hours were made practical. For small units, skid-mounting was a natural advancement in equipment design. These improvements have increased the utility and broadened the application of the dry desiccant unit.

EQUIPMENT

Vertical adsorber vessels. Vertical adsorbers are the most common style used today. Usually, internal construction of the vessels is simple; only a bed support is required near the bottom (Figure 1). Either downflow or upflow may be used, although downflow is favored since considerably higher velocities can be used, thus reducing the required diameter of the vessel. The gas is evenly distributed across the bed; usually without the need for baffles. Only minimum ground area is required for a typical installation. Foundations are more complicated than for horizontal adsorbers, unless the towers have been skid-mounted.

At low pressures, however, tower diameters become large because of limiting gas velocities. This can result in bulky, expensive vessels.

Operation at low flow rates becomes difficult since regeneration heat requirements remain unchanged. Within limits, unit operating conditions can be changed to compensate for this. However, a minimum regeneration gas



horizontal compartmented adsorber vessels. Vertical adsorber vessels are shown at right.

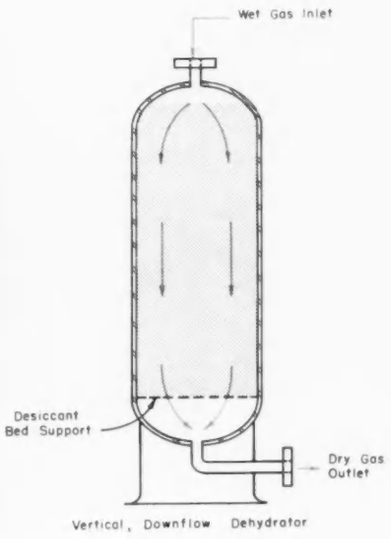


FIGURE 1

velocity of about 4 fpm is necessary to prevent channeling and for adequate bed reactivation.

Pressure drop through the vertical bed may be excessive for some applications. One type of vertical adsorber uses a radial flow pattern in order to reduce pressure drop through the bed. A second method used is the split flow[1] tower in which the wet gas enters the middle of the tower. The gas stream is divided, with half flowing through the upper bed and half flowing down through the lower bed (Figure 2).

Horizontal adsorber vessels. As shown in Figure 2, horizontal adsorbers are divided into several compartments by means of internal plates. A header arrangement distributes the gas to each compartment and a second header recombines the dry sales gas from the compartments.

Pressure drop is less than for vertical towers. Considering vessels of identical size, the horizontal adsorbers have a lower mass velocity through the desiccant bed than vertical towers, which reduces desiccant breakage.

During regeneration, all portions of the bed are reactivated equally. One of the outstanding advantages of the compartmented bed is being able to take one or more compartments out of service when operating on low flow rates.

Although horizontal adsorbers occupy more ground area, they are skid-mounted easily and can be trucked to location completely piped-up, since they do not exceed shipping height limitations. Foundations are simple, even for custom installations.

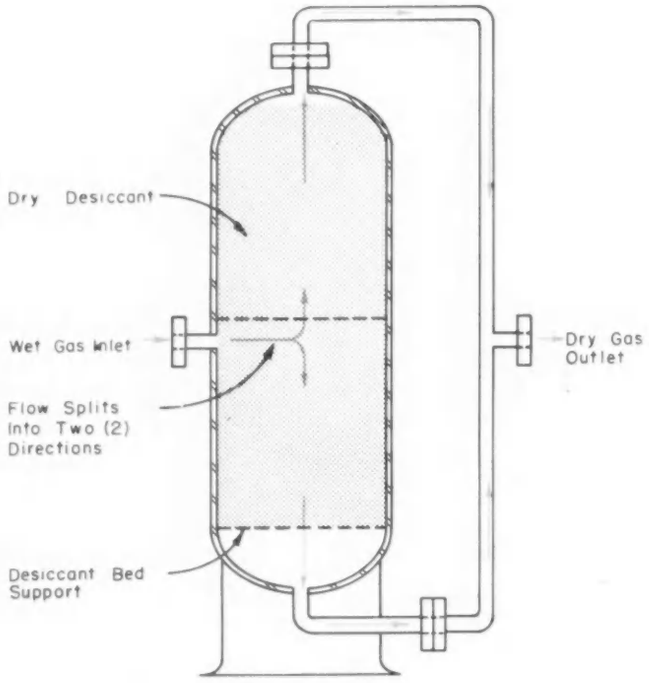
Scrubbers. Solid desiccants are easily poisoned.[2] While some desiccant beds have been used for as long as ten years, and four to five years is common, the presence of contaminants has been known to reduce drastically the adsorption capacity of a bed in a matter of weeks.

An adequate inlet scrubber is an integral part of a dry desiccant dehydrator. Some of the more active desiccants available today are highly susceptible to failure when doused with slugs of liquid water. Desiccant manufacturers have made available specially treated forms which are resistant to liquid water; however, these special forms, placed nearest the gas inlet, may be limited to about fifteen percent of the bed. The use of water resistant desiccants does not eliminate the need for an inlet scrubber, but only serves as added protection against the possibility of scrubber carry-over.

All desiccants in use today are affected adversely by heavy hydrocarbons. High molecular weight hydrocarbons plug the tiny pores in the desiccant, reducing their ability to adsorb water.[5] Repeated regeneration at relatively high temperatures tends to char these heavy fractions.

Compressor lube oil is a particularly difficult problem. Because of the conditions under which it is entrained, compressor lube oil is almost invariably present as a fog or mist which will pass through normal mist extractors. When this condition exists, the installation of a precontactor ahead of the adsorber removes the contaminant and helps to prolong desiccant life.

Precontactors are filled with spent desiccant from the dehydrator or any of the less expensive desiccants, such as bauxite. Such a desiccant will adsorb up to 25 percent of its weight in oil vapors. Although the precontactor fill can sometimes be reclaimed by steaming or washing in



Vertical, Split-Flow Dehydrator

FIGURE 2

a hydrocarbon solvent, it is usually discarded after several months of operation.

REGENERATION

For most applications, particularly unattended field installations, regeneration is accomplished by heating a side stream of the incoming liquid free raw gas; flowing the hot gas through the bed to be reactivated; cooling the gas from the bed to condense the water; separating the water from the gas and recombining the regeneration gas with the main stream before entering the active bed.

To accomplish side stream regeneration (also known as "open cycle" regeneration), a pressure drop is taken in the main gas stream equal to the pressure drop of the regeneration gas through the heater, wet desiccant bed, condenser, separator and piping.

On a large gas dehydration installation, a small compressor may be used to boost regeneration gas through the system.[3] Raw inlet gas may be used as in the open cycle, or closed cycle regeneration may be used in which the same gas is run through the system many times. This regeneration method reduces the over-all pressure drop required for the main stream to the pressure drop of the inlet scrubber, one desiccant bed and the interconnecting piping and switching valves. For companies operating centralized dehydration facilities, this means a saving of many dollars in compressor horsepower.

Heaters. The regeneration gas heater on most field installations utilizes a high temperature salt bath. Although somewhat more costly than the direct fired tubular heater, it has offsetting advantages. The constant high temperature salt bath holds a quantity of heat readily available for the regeneration gas when the controller switches to the heating cycle.

Possibility of tube failure is greatly reduced by decreasing the metal wall temperature and by eliminating severe hot spots, since tubes carrying high pressure regeneration gas do not come in direct contact with the heater flame. The salt commonly used in these heaters becomes corrosive if subjected to temperatures over 1,000° F, and will attack the metal tubes and firebox. For this reason a high temperature shutdown control is used which will override the normal operating controller.

When direct fired heaters are used, additional safety controls are installed which shut off regeneration gas flow and burner gas in the event of tube rupture or high stack temperatures. In plants, other heat mediums or high temperature steam may be used to heat regeneration gas.

ADVANTAGES AND DISADVANTAGES

Dry desiccant units utilizing a long cycle period must compete with other drying methods for most applications. In this regard, long cycle units are more expensive than glycol dehydrators or short cycle dry desiccant units. However, the long cycle unit will provide extremely low dewpoints over a wide range of operating conditions.

Equipment is dependable and can run on an unattended basis. Long periods of uninterrupted service are to be expected.

In addition to injury from heavy hydrocarbons, desiccant beds can be poisoned by hydrogen sulfide in the presence of oxygen and ammonia in the presence of carbon dioxide.

While the desiccants themselves are non-corrosive, acid gases present in the inlet stream will cause some corrosion, primarily in the heat exchanger and regeneration gas scrubber.

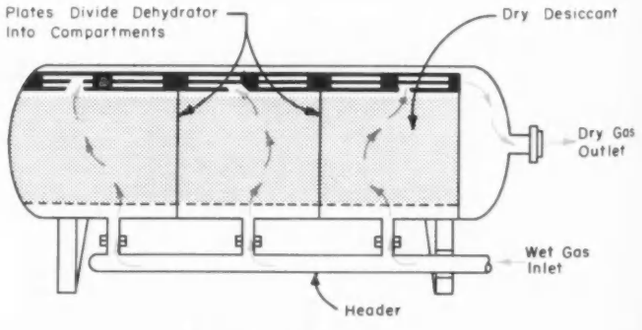
OPERATING PROBLEMS

Operating troubles can be divided into process problems and mechanical problems. It is obvious that process problems can be minimized if care is taken in the selection of proper equipment for the job. Occasionally, conditions exist which were unknown at the time the unit was purchased, or perhaps, developed at a later date.

Process problems. To combat corrosion, ammonia is sometimes injected ahead of the regeneration gas cooler. Although this helps to control the pH of the water being removed, it has a severe effect upon the desiccant.[2]

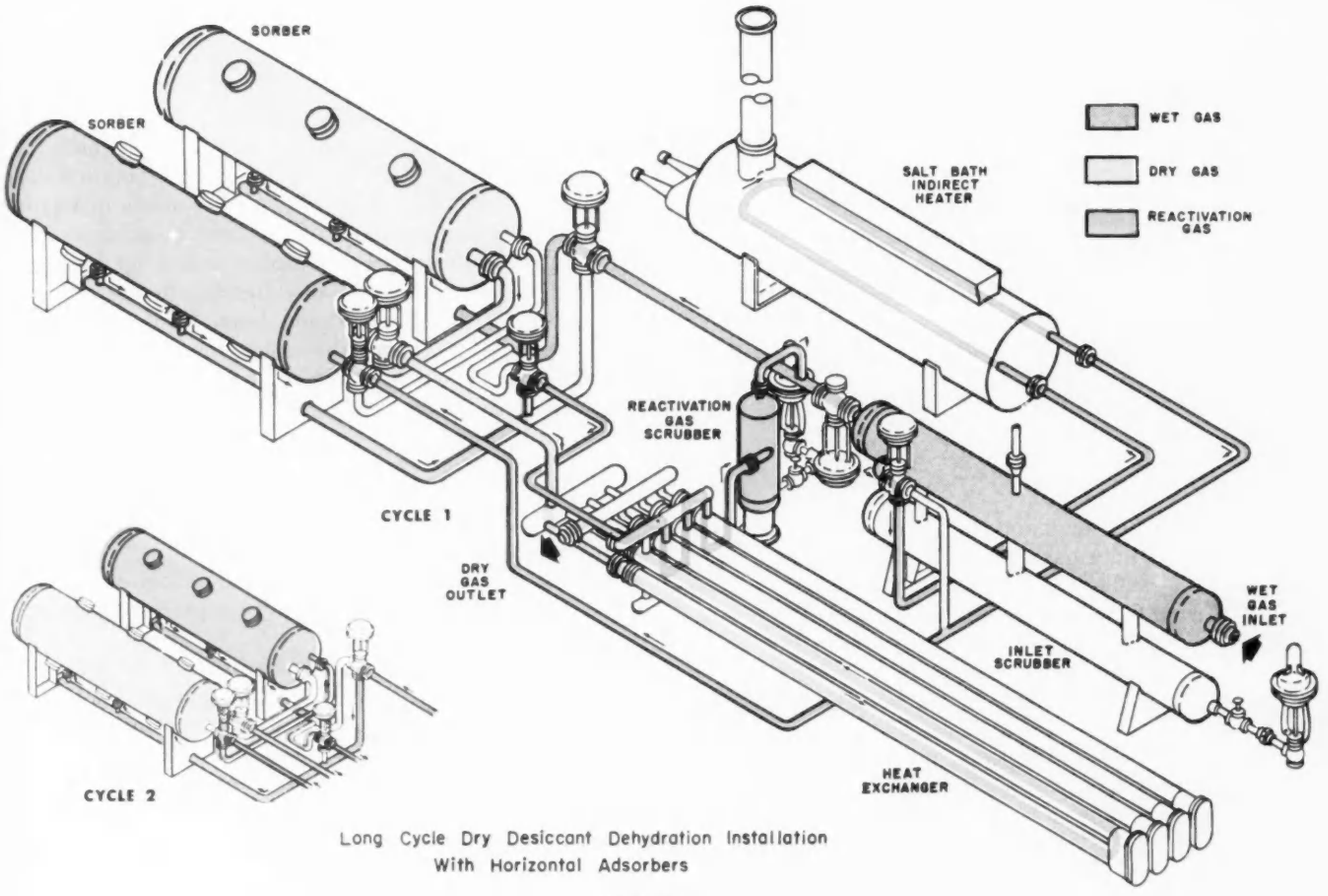
Ammonia and carbon dioxide react to form an unstable white solid which plugs the pores in the desiccant. Upon termination of the ammonia injection, repeated regeneration of the bed will restore some of the desiccant capacity for removing water.

Amine-based corrosion inhibitors used to combat down-



Horizontal Compartmented Dry Desiccant Dehydrator

FIGURE 3



Long Cycle Dry Desiccant Dehydration Installation With Horizontal Adsorbers

FIGURE 4

hole corrosion of tubing and casing in producing wells may find their way into the unit. The amine tends to break down at the high regeneration temperatures, resulting in the formation of free ammonia, thus providing the same undesirable results on the desiccant as discussed previously.

If it is desired to inject air into the gas stream for Btu content control, it would be well to inject the air downstream from the unit, dehydrating the gas sufficiently to produce the required dewpoint after the addition of the air, or dehydrating the air with glycol.[5] Otherwise, with the desiccant acting as a catalyst, even trace amounts of hydrogen sulfide will react with the oxygen to form free sulfur which will plug desiccant pores.

Breaking up of the desiccant bed will result in partial plugging of the bed and difficulty with compressors downstream. The desiccant breakage is usually the result of exceeding maximum allowable gas velocity, slugs of free water reaching sensitive desiccants, or sudden pressure surges.[6] It frequently becomes necessary to install a special filter in the main gas stream behind the desiccant beds.

Inadequate regeneration also can contribute to desiccant breakage by leaving liquid trapped in the bed. Gas bubbling through this layer causes erosion with fragments of desiccant accumulating in drifts. Sometimes, hard cakes of desiccant will form from this.

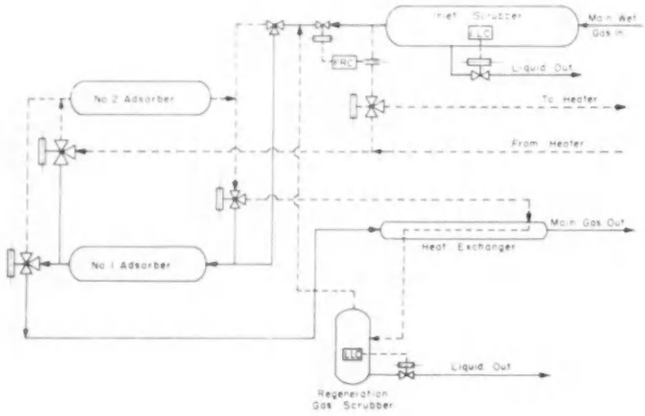
Mechanical problems. The heater, control system and results of corrosion can be considered the chief causes of mechanical operating problems.

On the heater, burner pilot light failure is usually caused by dirt and liquid deposits clogging the pilot light orifice. A small fuel gas drip and regular maintenance can avoid this problem. A damaged seat in the burner gas pressure regulator may cause the pilot light flame to be extinguished. This is a common failure on initial start-up until welding slag and foreign material has been cleaned from the line. For this reason, a strainer should be installed ahead of the pilot gas supply.

Inadequate regeneration will occur if outlet regeneration gas temperature peaks are not in the range of 350° F. To properly regenerate the desiccant, it may be necessary to vary the length of the heating and cooling portions of the regeneration cycle and vary the regeneration gas flow rate. In some cases, simultaneous regulation of both functions is required. Within the limits of the heater, it would probably be necessary to lengthen the heating portion of the cycle and increase the volume of gas flow during the cooling portion.

Inlet gas temperature also affects unit operation. If the inlet gas temperature is considerably below design temperature, the regeneration heater may be overloaded. If the inlet temperature becomes significantly higher than design temperature, the unit will be overloaded because of the increased water content of the gas. To compensate, the time cycle must be shortened, giving an "effective" increase in active desiccant. Shortening the cycle increases the regeneration heat requirements and, therefore, is limited by heater capacity. The gas quantity required for cooling the bed also will be affected.

Inadequate cooling of the regenerated bed will result in high sales gas temperatures immediately after switch-



Flow Diagram For Dry Desiccant Dehydrator

FIGURE 5

ing towers. The bed temperature should be within 30° F to 40° F of the inlet gas temperature before the switch. Increasing the cooling gas flow, or lengthening the cooling period should remedy the situation.

Continued high sales gas temperatures are the result of a different situation than described previously. Adsorber towers usually are sized for the maximum expected flow rate which must remain reasonably constant. If the quantity of main gas flow decreases, there is less mass for cooling the reactivation gas stream. Since the quantity of desiccant and volume of steel to be heated in the regeneration process is constant, the main gas outlet temperature must increase to dissipate the reactivation heat.

In most cases, this problem can be overcome by lengthening the adsorbtion, heating and cooling periods. This will put the same amount of heat into the sales gas per cycle, but there will be fewer cycles per day, resulting in less total heat rejected and lower sales gas temperatures. An alternate solution to the problem would be an external sources of cooling, such as an air or water cooled exchanger.

A third solution to the reduced flow problem is the use of horizontal adsorbers with compartmented beds (Figure 2). Some of the compartments can be blanked off, diverting the main gas through a sufficient number of compartments to assure good dehydration at the reduced load. Then, only the compartments in use need to be regenerated which restores the balance between regeneration heat and main gas volume.

The control system is the second source of mechanical problems. A dependable source of supply gas is essential for proper operation. The supply medium should utilize dehydrated gas taken from the outlet section of the sales gas line. Many units operate in the 800 psi to 1,000 psi pressure range with 7 lbs./MMscf or less of water in the outlet gas. However, this amount of water is sufficient to form hydrates in the supply gas system during cold weather if the pressure reducing system is not designed properly.

One of the easiest methods of handling this problem is to reduce the supply gas pressure in two stages. Adequate, unrestricting flow lines between stages of pressure reduction should be installed to permit the gas to warm up before the second pressure drop.

A second method is to heat the supply gas before expanding to the lower pressure to keep the gas always above the hydrate temperature.

A third method is to expand the gas into a heat source, such as a coil in the outlet gas line. Some manufacturers offer a special "no freeze" regulator to automatically control this function.

Extremely cold weather also affects control valve operation; particularly the small auxiliary valves which may be used as relays to actuate the main diaphragm valves. Dirt or moisture deposited on the valve stems in warmer weather may cause sluggish operation in cold weather, resulting in improper or incomplete switching.

Cold weather also may cause freezing in the regeneration separator and liquid dump lines. Insulation of both the vessel and the pipe is the easiest solution to the problem. Where the installation justifies the additional expense, a small heater and glycol circulating pump can be installed in order to trace critical lines with hot glycol.

If the freeze-off occurs only at the dump valves, special cold weather valves are available which allow a pressure reduction across the valve seat inside the scrubber. Such an arrangement minimizes freezing.

Leaking control piping may result in loss of sufficient instrument or control valve supply gas pressure to prevent complete switching.

Occasionally, a ruptured valve diaphragm or scored valve trim will allow hot regeneration gas to leak by when the regenerated bed should be on the cooling portion of the cycle. This situation will be evidenced when cooling gas to the bed is at a higher temperature than the main stream.

Corrosion is a third possible cause of mechanical failure of this type dehydrator. Normally, corrosion is not a serious problem unless carbon dioxide and hydrogen sulfide are present. In such instances, the corrosion usually occurs in the heat exchanger where water is condensing in the presence of the acid gases. Very extreme corrosion has been noted where both carbon dioxide and oxygen are present in the inlet gas stream. When corrosion in the heat exchanger is severe enough to cause leakage of gas from the shell side to the tube side, the mixing of the regeneration gas with the sales gas will result in an unsatisfactory dewpoint from the unit.

APPLICATIONS

The appearance of the short cycle dry-type dehydrators and the increased range of application now available in glycol units seems to narrow the market for the older, long cycle process.

However, because of conservative design, the long cycle dry-type units still will find favor when a water content of 1 lb./MMscf of gas or less is desired, or when inlet gas temperatures are over 100° or under 50° F. By careful design, dewpoints as low as minus 90° F are possible with this process.

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4. THE CALCIUM CHLORIDE GAS DEHYDRATOR

By R. H. Ackermann, Process Engineer
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THE CALCIUM CHLORIDE gas dehydrator has been found to operate efficiently over a wide range of gas flow rates, pressures and temperatures. Many units are in service operating at temperatures ranging from 50° F to 120° F, and at pressures ranging from 100 to 2,000 psig. These units are designed to have a maximum 8 psi pressure drop at gas flow rates from 1 to 20 MMscf per day. The unit has no moving parts, requires no regenerative heater or process pump and will operate efficiently and unattended for long periods of time. It is particularly suited to remote locations which are inaccessible for long periods because of adverse weather conditions.

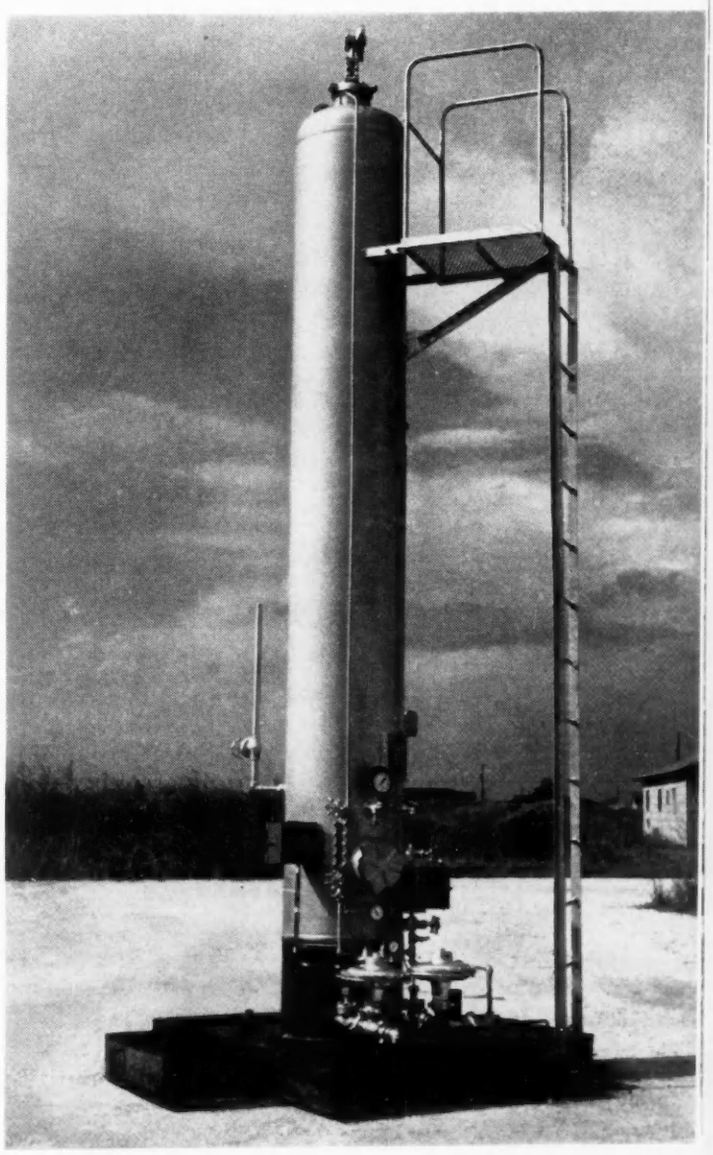
Internal corrosion has not been a problem because water vapor formed has a preferential affinity for the calcium chloride and corrosive acids are not formed even though hydrogen sulfide and carbon dioxide are present. As a result, these units have been used successfully to dehydrate natural gases containing as much as 60 percent hydrogen sulfide.

The calcium chloride dehydrator uses a solid chemical bed for complete dehydration. For economy, a series of self-circulating trays are used to handle the brine formed. Brine discharged from a unit of this type is dilute, and the calcium chloride it contains is considered expendable. At present, there are over 600 dehydrators of this type operating throughout the United States and Canada.

GENERAL DESCRIPTION

The calcium chloride dehydrator is a combination three-phase separator, gas-liquid absorption tower and solid chemical bed desiccant unit. Figure 1 is a cross-sectional view of the vessel.

The lower section is a gas-liquid separator which separates free liquids, hydrocarbons and water, from the in-



Calcium chloride gas dehydrator

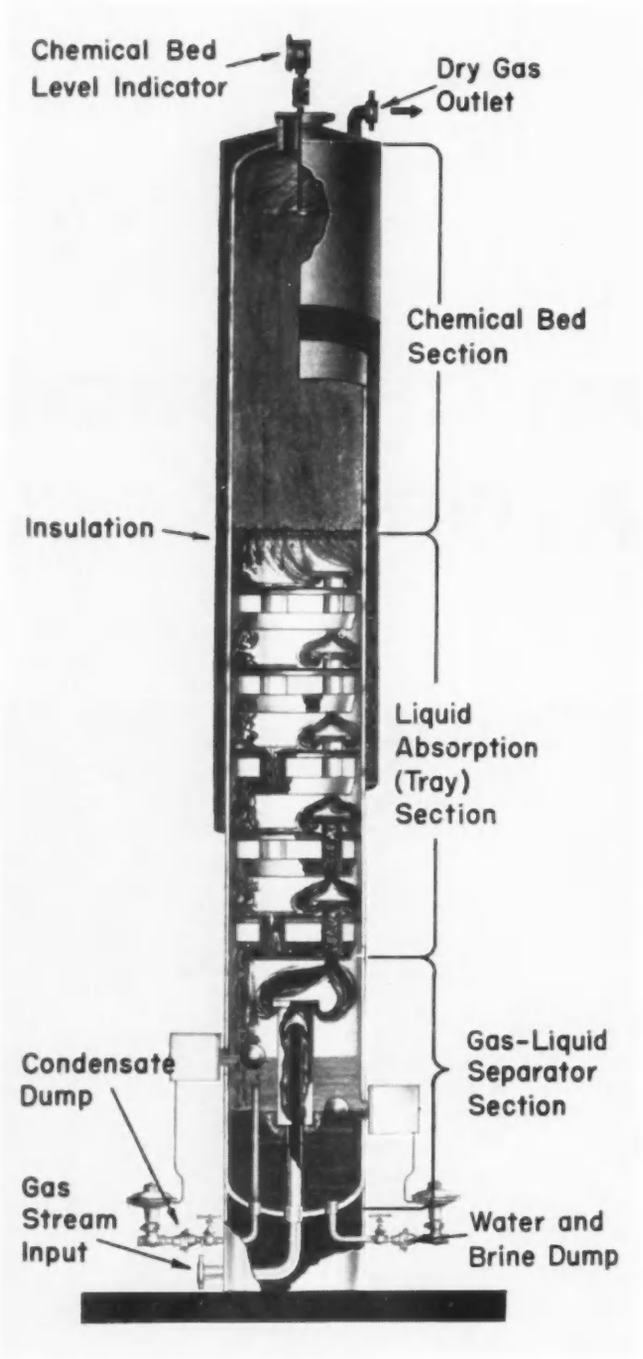


FIGURE 1

coming gas stream. The middle section is the liquid absorption section where the brine removes most of the moisture from the gas in a series of five self-circulating trays. The upper section contains the solid calcium chloride which absorbs the final traces of water and furnishes the brine feed for the tray section.

Separator section. Incoming wet gas and free liquids enter the dehydrator at the bottom of the separator section and flow upward through a liquid disengager, where the majority of the free liquids are scrubbed from the wet gas stream. Liquids not removed in the disengager separate by gravity as gas velocity decreases upon entering the greater area in the upper portion of the separator.

Water and liquid hydrocarbons, if any, collect in the bottom of the separator and are individually and automatically discharged from the unit by liquid level controllers. Gas, now free of entrained liquids, flows upward to the botom tray in the brine absorber section.

Liquid absorber section. In the absorber section, the concentrated brine dripping from the solid chemical bed section absorbs water from the gas as it flows downward by gravity from tray to tray, counter-current to the wet gas rising from the bottom. A nozzle on each tray contacts the brine and gas as the gas flows upward through each tray in series. At the outlet of each nozzle, the brine separates from the gas and falls back to the tray to be recirculated.

As the gas continues upward through the tower it is progressively dehydrated. As the brine-absorbing water progresses downward through the tower, it is gradually diluted. By the time the gas has passed through the top tray, more than 50 percent of the water vapor originally contained is absorbed.

This partially dehydrated gas then enters the solid chemical bed section for final dehydration. Brine leaving the bottom tray joins the free water in the separator section and is discharged from the unit.

Solid chemical bed section. Calcium Chloride is a deliquescent chemical which absorbs water to form four hydrates before changing to the liquid state. The areas shown on the phase diagram (Figure 2) illustrate these chemical changes as a function of temperature and composition.

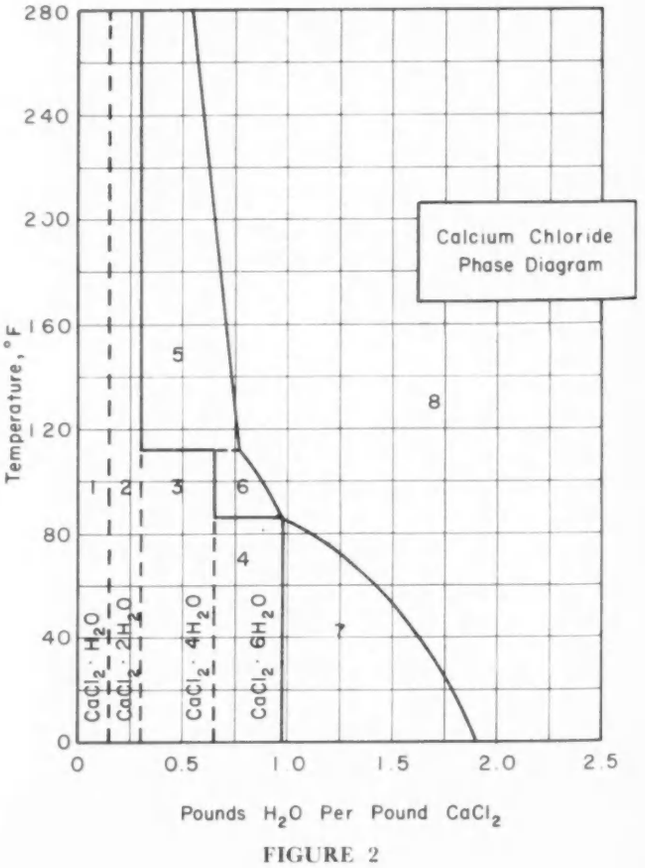


FIGURE 2

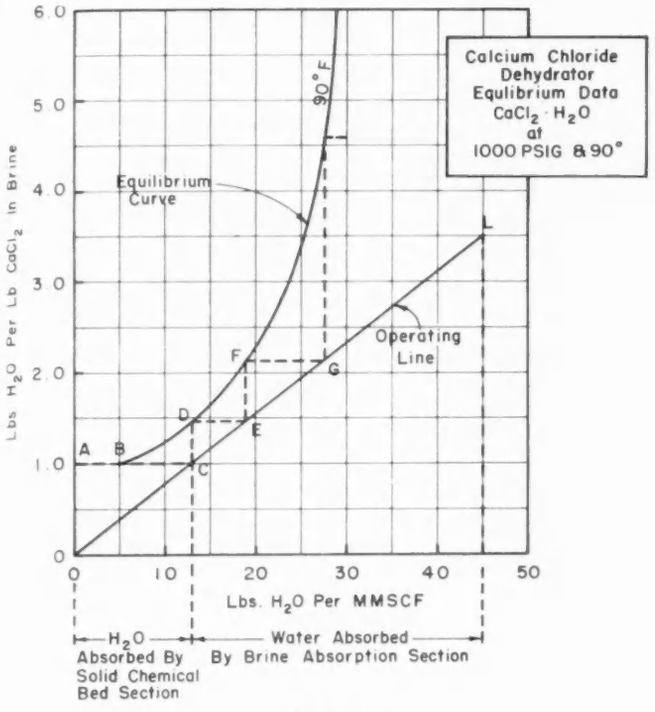

Calcium Chloride Dehydrator Equilibrium Data $CaCl_2 \cdot H_2O$ at 1000 PSIG & 90°
90° F
Equilibrium Curve
Operating Line
Lbs H_2O Per Lb $CaCl_2$ In Brine
Lbs. H_2O Per MMSCF
H_2O Absorbed By Solid Chemical Bed Section
Water Absorbed By Brine Absorption Section

FIGURE 3

Area 1—solid anhydrous $CaCl_2$ and $CaCl_2 \cdot H_2O$.
Area 2—solid $CaCl_2 \cdot H_2O$ and solid $CaCl_2 \cdot 2H_2O$.
Area 3—solid $CaCl_2 \cdot 2H_2O$ and solid $CaCl_2 \cdot 4H_2O$.
Area 4—solid $CaCl_2 \cdot 4H_2O$ and solid $CaCl_2 \cdot 6H_2O$.
Area 5—solid $CaCl_2 \cdot 2H_2O$ and sat'd solution.
Area 6—solid $CaCl_2 \cdot 4H_2O$ and sat'd solution.
Area 7—solid $CaCl_2 \cdot 6H_2O$ and sat'd solution.
Area 8—Homogenous Brine.

When dehydrating gas, the solid calcium chloride in the bed section undergoes the same chemical changes as shown on the phase diagram in Figure 2. The bottom of the bed which first contacts the wet gas is represented by area 7, where $CaCl_2 \cdot 6H_2O$ is in equilibium with its saturated solution. Here, the calcium chloride is in the final stage of being a solid hydrate and is slowly forming brine as more water is absorbed.

Above this point, the bed becomes successively drier until at a point approximately two feet from the bottom, the gas is in contact with dry anhydrous chemical (Area 1, Figure 2). Between these lower and upper limits, the chemical varies in state between the sixth hydrate and the anhydrous material (Areas 2, 3, 4, 5 and 6).

As the chemical is consumed from the bottom, the weight of the dry material above causes the bed to settle, replacing the dry anhydrous chemical in the dehydrating zone. This operation continues until only two feet of bed remain, at which point the unit is recharged (A bed level indicator shows the amount of bed remaining at all times, Figure 1).

In some instances, the chemical bed section in early units channelled and/or did not settle properly (bridging) as the chemical was consumed. These problems have been almost entirely eliminated in later models. Centrifugal gas distributor nozzles are used at the bottom of the bed to prevent channelling, and plastic coating the bed section prevents chemical from adhering to the vessel wall and causing bridging.

Although channelling or bridging does not generally create a problem, if it occurs it can be detected by a higher outlet gas dew point than normal. If channelling or bridging is suspected and an unsatisfactory dew point is evidenced, the trouble may be corrected by using a brass rod (to prevent sparks) to agitate the bed section. Also, water may be poured around the edges of the bed section which will cause the bed to settle. If necessary, fresh chemical may then be added.

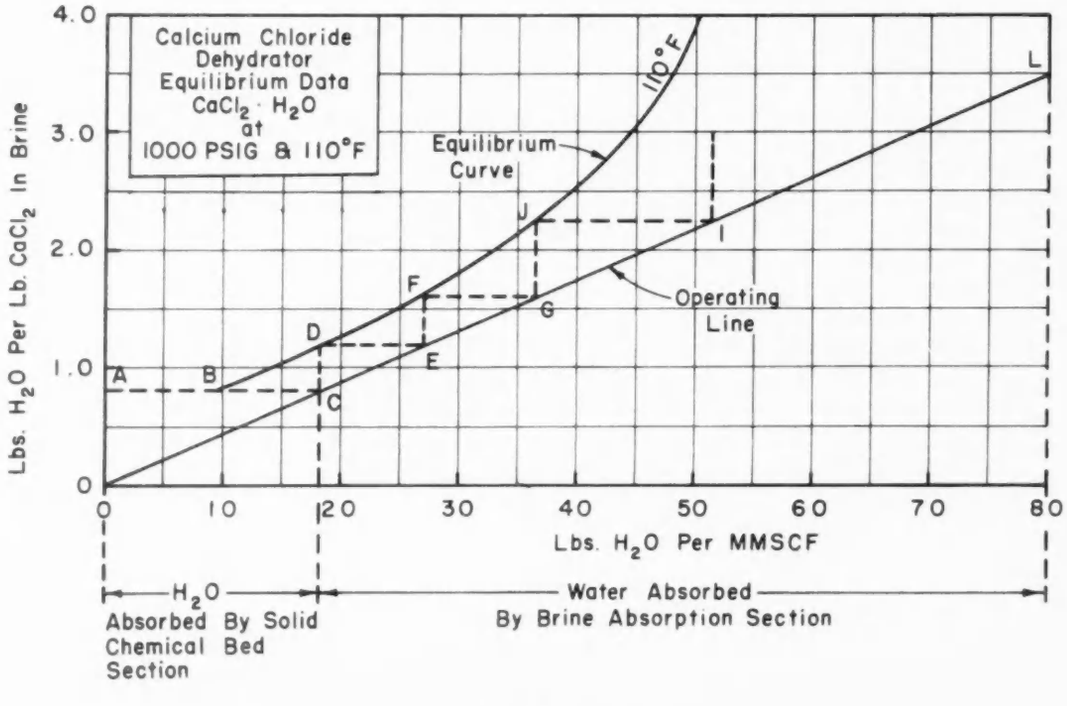
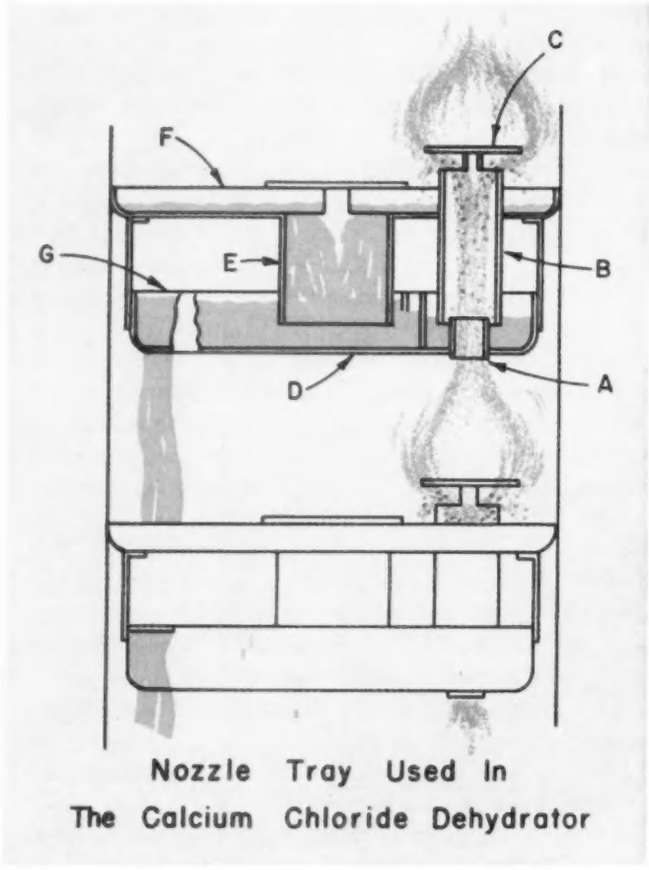

Calcium Chloride Dehydrator Equilibrium Data $CaCl_2 \cdot H_2O$ at 1000 PSIG & 110°F
110° F
Equilibrium Curve
Operating Line
Lbs. H_2O Per Lb. $CaCl_2$ In Brine
Lbs. H_2O Per MMSCF
H_2O Absorbed By Solid Chemical Bed Section
Water Absorbed By Brine Absorption Section

FIGURE 4



Nozzle Tray Used In The Calcium Chloride Dehydrator

FIGURE 5

BRINE ABSORPTION SECTION OPERATING DATA

Figure 3 is a graphical method of predicting operating performance of the brine absorption section. Determined from this diagram are: (1) number of trays required in the absorber section, (2) the quantity of water that will be absorbed by the brine, and (3) equilibrium that will exist between the water in the calcium chloride brine and the water in the gas (at 90° F and 1,000 psig, in this example).

Any point of the curve describes a condition of equilibrium when the partial pressure and vapor pressure of the water in the gas and brine are equal. At equilibrium, there is no exchange of water vapor between the gas and brine. For example, a brine containing 2 pounds H_2O/lb. $CaCl_2$ will absorb water from a gas if it contains more than 18 pounds H_2O/MMscf. The same brine will lose water to a gas containing less than 18 pounds H_2O/MMscf. Equilibrium will exist when the water content of the brine and gas is 2 pounds H_2O/lb. $CaCl_2$ and 18 pounds H_2O/MMscf, respectively.

Line LM (Figure 3) is the operating line which expresses the limit of equilibrium that can exist on any tray. This line, which connects the water content of the gas and brine at the top and bottom of the absorber, is determined from a material balance around the entire absorber. The material balance equation for this line is:

$$\text{Gas } (\text{Water}_{\text{inlet}} - \text{Water}_{\text{outlet}}) = \text{Brine } (\text{Water}_{\text{outlet}} - \text{Water}_{\text{inlet}})$$

This is the equation of a straight line, and it indicates that the water lost by the gas is equal to the water gained by the brine. The steps formed by the dotted lines drawn between the equilibrium curve and the operating line indicate the minimum number of theoretical trays required in the absorber section.

The distance between points A and C on Figure 3 represents the quantity of water (13 pounds H_2O/MMscf) that will be extracted from the gas in the solid chemical bed section. Point C indicates that the gas leaving and the brine entering the top-most tray in the brine absorption section contains 13 pounds H_2O/MMscf and 1 pound H_2O/lb. $CaCl_2$, respectively.

Brine on the top tray will absorb an amount of water equal to the length of line DE (6 pounds H_2O/MMscf) and will change water content from 1.0 to about 1.45 pounds H_2O/lb. $CaCl_2$ as indicated at Point D. On the next lower tray, the brine will change in composition from 1.45 pounds H_2O/lb. $CaCl_2$ (Point E) to that shown at Point F, 2.15 pounds H_2O/lb. $CaCl_2$. Also, the

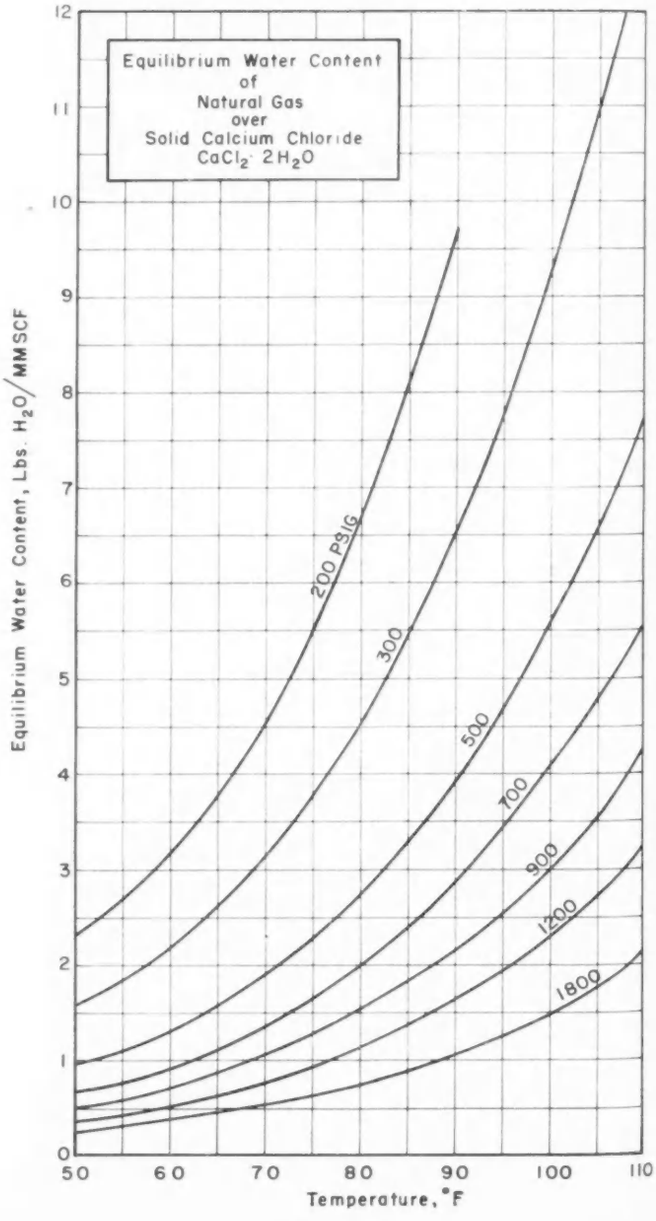


FIGURE 6

brine will absorb about 9 pounds H_2O/MMscf from the gas as indicated by the length of line FG. Water content of the gas and the change in brine composition on each theoretical tray can be determined in a like manner from Figure 3.

Figure 4 is a similar diagram predicting the operating characteristics of the tray section of a calcium chloride dehydrator operating at 110° F and 1,000 psig. The importance of the brine absorption section becomes apparent when it is noted that the brine absorbs over twice as much water as does the solid anhydrous chemical. Figure 3 indicates that 32 pounds H_2O/MMscf are absorbed by the brine, leaving only 13 pounds H_2O/MMscf to be removed by the solid chemical bed section.

NOZZLE TRAY

The brine absorption section of the dehydrator contains five special gas-liquid contacting trays. Conventional bubble cap and perforated trays are unsatisfactory because they are not adapted to the peculiar operating conditions found in this unit. These conditions are:

1. Handling a concentrated brine at temperatures only slightly above brine freezing point temperature.
2. Operating efficiently without an external reflux pump when the ratio of the liquid down-flow rate to the gas steam up-flow rate is small.

For example, a dehydrator processing 3 MMscf of gas per day (at 90° F and 1,000 psig) produces only 15-16 gallons of brine per day (Figure 3). With this small quantity of liquid, a conventional tray would require a reflux pump to operate efficiently. Referring to Point C in Figure 3, a 50 percent $CaCl_2$ brine has a freezing point of 85° F (Figure 2) and will solidify in a dehydrator during prolonged shut-down periods in cold weather. Should the brine solidify on a conventional tray, gas passages would become plugged and a damaged tray would result when operations were resumed.

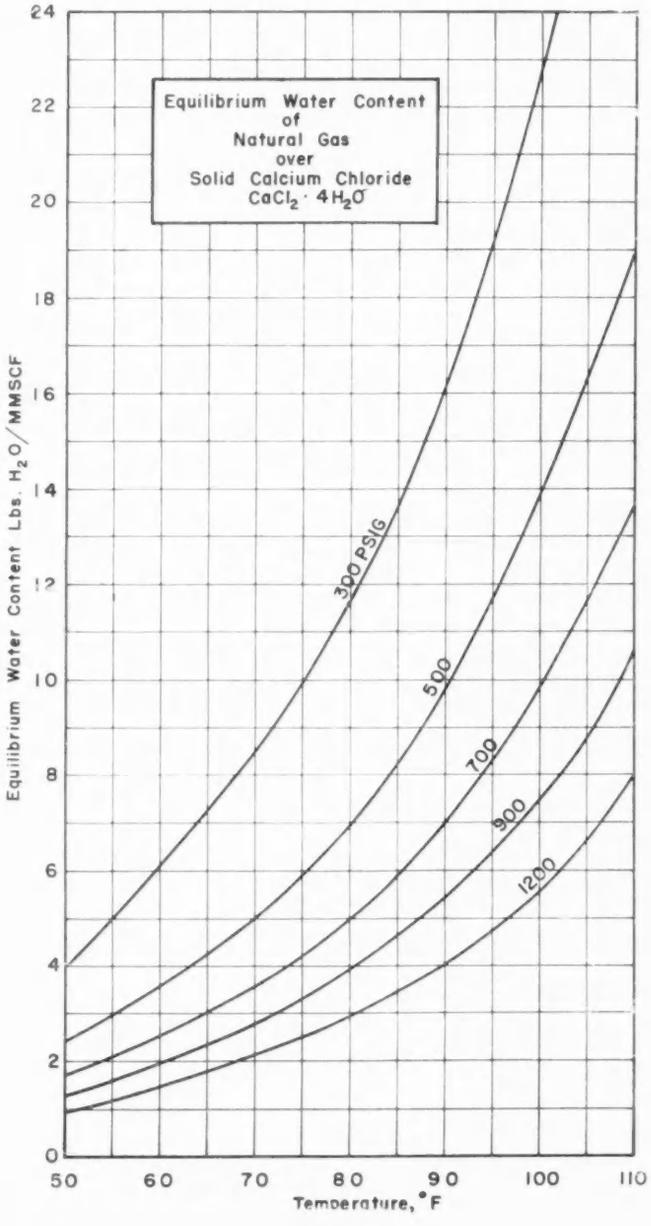


FIGURE 7

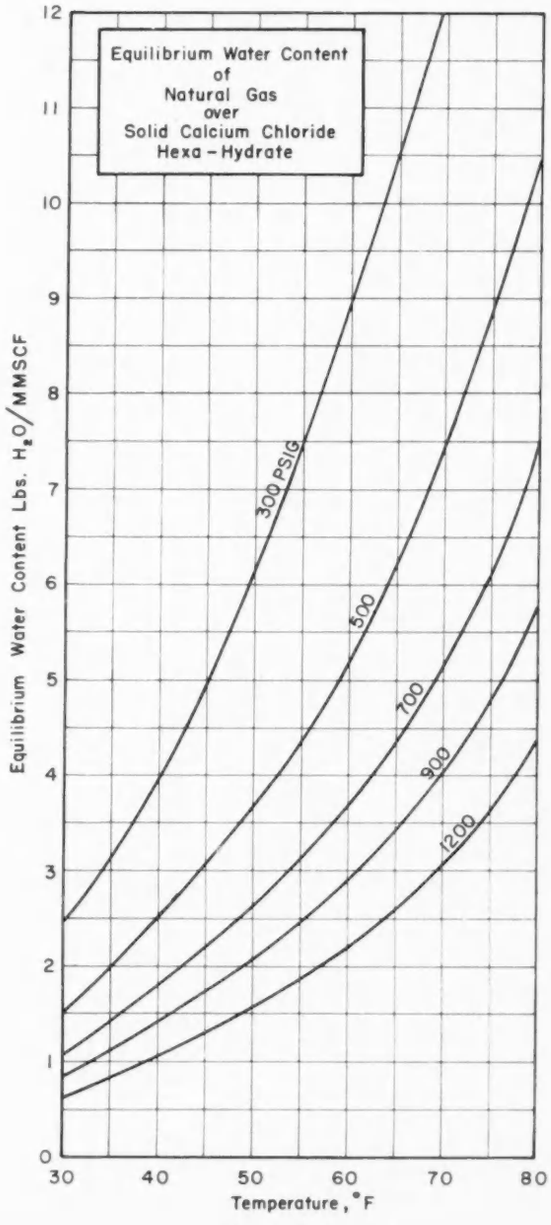


FIGURE 8

These problems were solved by designing a self-refluxing tray (Figure 5) using the aspirator action of the gas passing through a nozzle on each tray to circulate the brine and provide reflux liquid.

Referring to Figures 5, gas flowing at a high velocity through nozzle A, picks up brine in the form of a mist and small droplets. These droplets are carried upward, where they are intimately commingled with the turbulent gas in mixing chamber B. The heavier brine particles separate from the gas at the outlet of the mixing chamber, and are deflected downward by deflector plate C to collecting tray F. The brine then flows by gravity to sump D through downcomer E where it is again picked up by the gas and recirculated. Excess brine that accumulates in the sump spills over weir G to the tray below. The gas then continues to the next tray above.

This type tray was found to operate efficiently because (1) the large surface areas exposed to the gas in the form of mist and droplets increased the water absorption rate, (2) reflux rate is adjusted automatically by the gas to changes in the gas flow rate and (3) turbulence promoted by the nozzle insures complete mixing between the gas and brine, so that fewer actual trays are required in the absorber. Also, nozzles are of sufficient size to resist plugging by solidified brine.

DEHYDRATOR EFFICIENCY

The cost of operation (pounds $CaCl_2$/MMscf) and the dewpoint of the outlet gas are both functions of operating pressure and temperature. Increasing pressure and decreasing temperature increase the ability of both the liquid absorption and chemical bed sections to absorb water. Increasing the efficiency in the liquid absorption section reduces the dehydration cost, and increasing the efficiency of the chemical bed section reduces the water content of the outlet gas.

Equilibrium data for the liquid absorption section (Figures 3 and 4) illustrate that for the same outlet brine concentration, fewer trays are required at higher pressures and lower temperatures. While the trays have a significant effect on the economic behavior of the unit, they have little effect on the final dewpoint of the outlet gas. The water content of the effluent gas is governed by the equilibrium conditions that exist between the solid chemical in the uppermost section and the water vapor in the gas in that section.

Figures 6, 7 and 8 express this relationship as a function of temperature, pressure and outlet gas water composition for the three stable calcium chloride hydrates, the second, fourth and sixth hydrates. These hydrates form in the lower two feet of the chemical bed section. The very bottom of the bed which is in contact with the partially dehydrated gas from the tray section, is in the sixth hydrate stage and is slowly changing to the liquid state. Progressing upward, the gas reaches a zone which is predominately the fourth hydrate, then upward to the second hydrate and so on, until a distance approximately two feet from the bottom the gas comes in contact with the anhydrous material.

The equilibrium relationship between the solid chemical and water vapor illustrates the water absorption mechanism in the chemical bed section. It can be visualized that the gas is progressively dehydrated as it flows upward through these theoretical hydrate zones. When a dehydrator operating at 900 psig and 80° F has reached equilibrium conditions, water content of the gas passing through the sixth hydrate zone will be reduced to 5.7 pounds H_2O/MMscf. Upon leaving the fourth hydrate zone, the gas will contain only 4 pounds H_2O/MMscf, and finally, as it leaves the second hydrate stage, it will contain only 1.55 pounds/MMscf, assuming equilibrium. More water will be extracted as the gas contacts the anhydrous chemical.

Water content of the effluent gas will depend, to a certain extent, upon the length of time the chemical bed has been in service. It is possible, after an extended period of operation (approximately three months or more), for the entire upper portion of the anhydrous chemical to be converted to the duo hydrate stage. A good rule-of-thumb to use in predicting the outlet gas dewpoint is to assume the gas is in equilibrium with the duo hydrate stage. (Figure 6).

CORROSION

Calcium chloride is not corrosive except in the presence of free oxygen. The interior of a dehydrator or pipe line handling calcium chloride, protected from the atmosphere, exhibits no signs of corrosion. Nothing but smooth corrosion-free steel was found when calcium chloride dehydrators processing natural gas were opened and examined after five years of operation. These results are attributed to the fact that natural gas contains no free oxygen.

Natural gas containing H_2S has been dehydrated successfully with no ill effects. There is no chemical reaction between the $CaCl_2$ and H_2S because the tendency is greater for the products which would form to react with each other forming hydrogen sulphide and calcium chloride:

$$CaS + HCl \rightarrow CaCl_2 + H_2S \uparrow$$

Dehydrators processing natural gas containing as much as 60 percent H_2S have been operating successfully for the past two years.

DEHYDRATION CAPACITY

With a given size chemical bed, operating time between recharges is directly proportional to the quantity of water absorbed in the dehydrator. The quantity of water absorbed can be determined easily from the water dewpoint temperature of the outlet gas when the incoming gas stream is water saturated. For example, 39 pounds H_2O/MMscf will be absorbed when a dehydrator is producing a 6 pounds/MMscf outlet gas from an inlet water saturated gas containing 45 pounds H_2O/MMscf at 1,000 psig and 90° F.

Figure 3 indicates that the brine from the unit, containing three-plus theoretical trays, will have a composition of 3.5 pounds H_2O/lb. $CaCl_2$. This indicates that one pound of $CaCl_2$ will absorb 3.5 pounds H_2O. Therefore, a unit containing 1,750 pounds (five drums) of $CaCl_2$ in the chemical bed section, would absorb 6,125 pounds of water before the bed was depleted. However, since recharging usually is done when two feet (one 350-pound drum) of chemical remains, 4,900 pounds of water could be removed between recharges. Assuming 39 pounds of water removed per MMscf, this means that 125 MMscf could be processed between recharges.

This manual will be continued in the February 1 issue of World Oil

New drilling technique recovers 100 percent continuous core

This method uses dual drill pipe, a highly portable rig, electric swivel and a new concept of circulation practices

By Homer Henderson
Chief Engineer, Strato Drill Inc.
Houston

Jack F. Earl
Engineering Editor, WORLD OIL

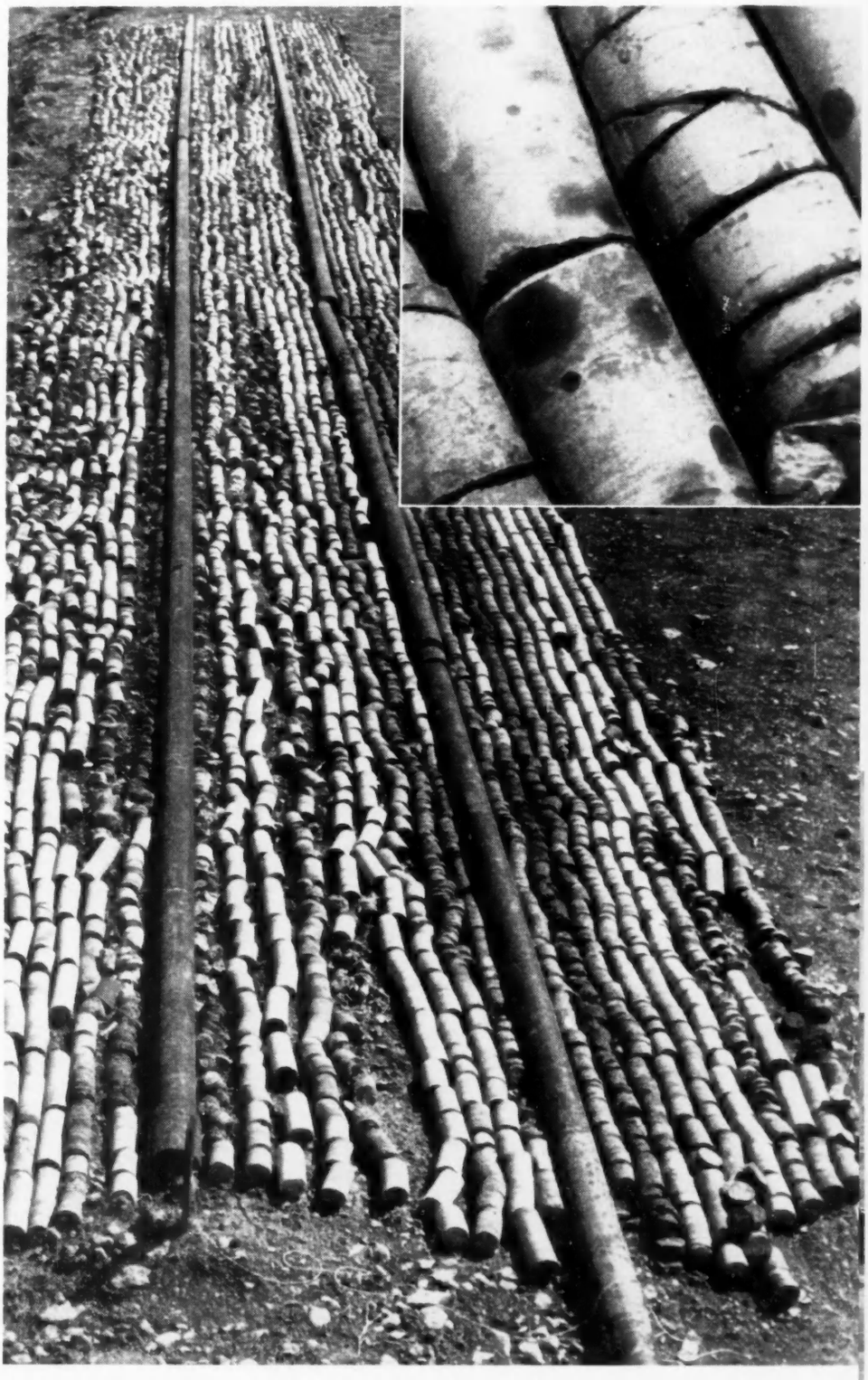
FROM THE BEGINNING of rotary drilling at Spindletop to the present day rotary operations, little has been done to improve basic drilling methods. The principal developments have been in equipment and practices required for deeper drilling.

However, a continuous coring method recently has been introduced. While seismograph and other geophysical and geological exploratory techniques have been used extensively and successfully in finding oil reserves, these methods are limited to structural trap indications and not used primarily to locate hydrocarbon accumulations in stratigraphic traps. Drilling is the only known method to satisfactorily find and develop these traps. And drilling is costly and not too satisfactory.

If better subsurface information were available, stratigraphic traps could be located with greater efficiency. Some geologists believe that 75 percent of the oil remaining to be found in the United States is located in stratigraphic traps. With this objective, the new method of exploration and drilling was developed.

The operation of this new drilling technique was conducted in an old developed oil province near Abilene, Texas. This test was successful in recovering 100 percent cores for the depth drilled, and it pointed to the practicability of this technique for use in exploratory and development drilling.

A continuous core may be taken



A 100 percent recovery of 1,400 feet of hole is shown laid out on the ground so that a true evaluation of the formation may be obtained. The insert shows a close-up of the core as retrieved in 2-inch by 6-inch samples.

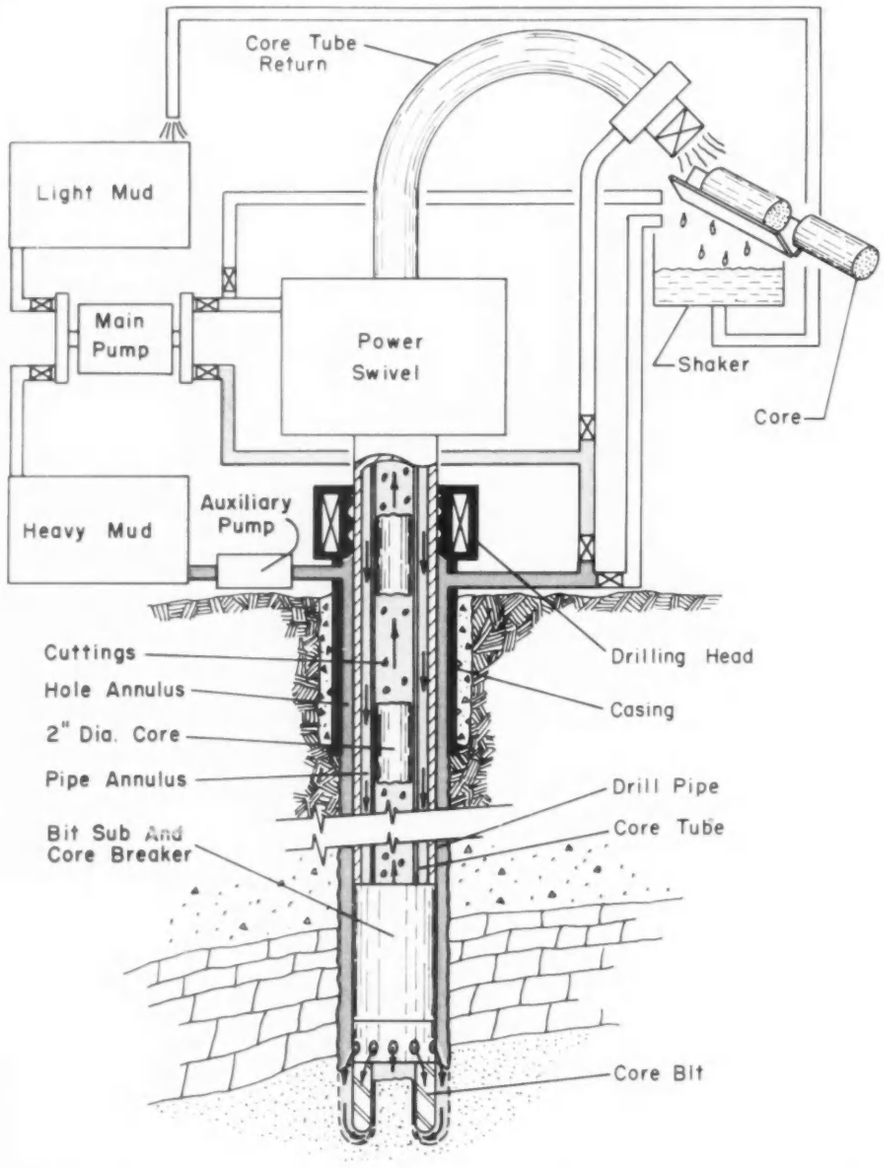


FIGURE 1—A schematic drawing showing the significant component parts of the new drilling technique during drilling operations.

TABLE 1—Comparison of hydraulic requirements of the dual drill method vs. conventional method

Basis:
Hole size: 7-inch
Ascending mud circulation velocity: 3 feet per second
Mud: 9.5 ppg
Viscosity of mud: 3 centipoises
Conventional drill pipe OD: 3½-inch API
Dual drill pipe OD: 4-inch and 2½-inch core

DRILL	Mud Volume gal/min.	Friction Pressure Loss Per 1000 ft. Descending	Friction Loss Per 1000 ft. Ascending	Total Friction Loss/1000 ft.	Friction Horsepower Requirements Per 1000 ft.
Conventional	270	140	13	153	34.5
Dual drill	37	17.5	11	28.5	0.86
Ratio: Conventional/Dual drill	7.3/1	8/1	1.1/1	5.4/1	40/1

from the grass roots to total depth. A reverse circulation method is used by circulating down the pipe annulus and up the central core tube (Figure 1).

Present operations include cutting a 4¾-inch hole and retrieving a full gage 2-inch core. The outer tubular pipe is 4 inches in diameter and is outside flush. The core is cut and broken off in 6-inch increments (Figures 1 and 2) and circulated to the surface through the core tube. The tube extends through the top of the derrick (Figure 1), and is attached to the side of the derrick and extends over to the shale shaker. The core then is retrieved in 5-foot trays from the shale shaker and placed sequentially in rows for the full section of the hole cut.

Rig operation and equipment. The rig trailer unit is highly mobile. The rig is transported in the position shown in Figure 3. Figure 4 shows the rig erected on location.

The mast is a 38-foot, four-legged, 3½-inch cylindrical tubing mast. It is rated at 100,000-pound hoisting capacity. The mast is folded down (Figure 3) while being transported and, in drilling operation, it is rigidly pinned to the trailer bed. The steel mesh derrick floor rests on the ground level, and has leveling jacks to keep the mast plumb.

The drill pipe consists of two strings of pipe welded together and rotated as an integral unit. The area between the two pipes is called the tubular annulus; the area of the inner pipe is called the core tube (Figure 1).

The power swivel is equipped with two 20 hp electric motors having field excitation speed and torque control. Power is transmitted to the drill pipe through a set of gears. The swivel's rotational speed and torque, regulated by the driller, will efficiently rotate at speeds from 30 rpm to 500 rpm.

The crown block has four sheaves with four working lines attached to the drawworks. A 165-hp engine powers the drawworks.

The circulation system consists of one 2½-inch rotary hose attached to the inlet of the pipe annulus at the swivel. Core and cuttings are circulated out through the core tube, which is 2½ inches in diameter, to a squirrel cage type shale shaker and thence to the mud tanks. A 4-inch x 6-inch mud pump circulates the fluid. The pump can circulate satisfactorily to a depth of 5,000 feet. Air can sup-

plement mud, if desired, since satisfactory results were obtained with air.

Bits currently used are diamond or bladed types, depending upon anticipated lithology. A 2-inch core is cut, leaving little formation to be drilled up. Cuttings are removed with the core through the core tube.

After the cores and cuttings are flushed through the core tube to the surface and the shale shaker, the cores are picked up and placed in a 5-foot core tray to correlate with the driller's 5-foot measuring stick. After each 5-foot interval, cores are placed in storage, which may be long trays labeled as to the exact depth.

Laid out in these trays, cores may be inspected at any time to determine what has been drilled through or what currently is being drilled. Because of the high velocity within the core tube, the time for core transit to the shaker is short. The core retrieved at the shale shaker at any instant is a sample of the formation only a few inches above that which is presently being drilled. The normal rate of return velocity is maintained at about 5 minutes per 1,000 feet.

After encountering a drilling break, the driller may cut an additional six inches of formation and circulate the core to the surface. Thus, formation tops may be measured accurately. For checking purposes and accurate depth measurements, a wire line measure-

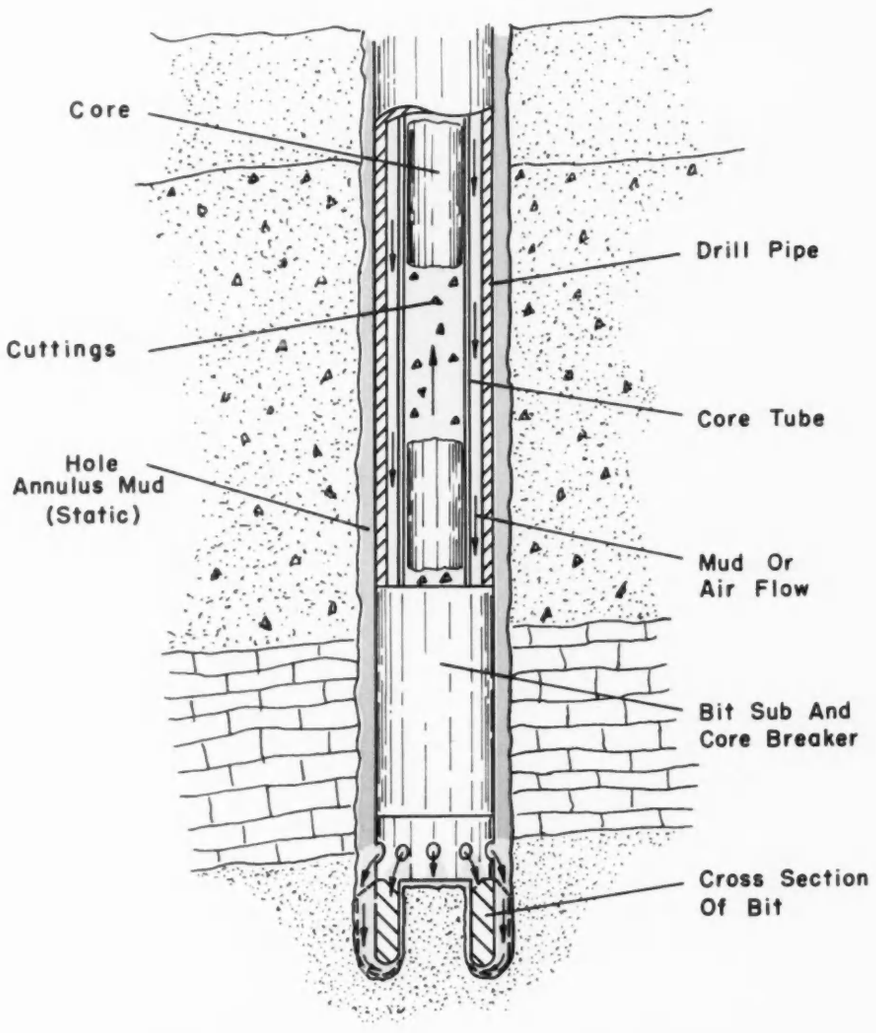


FIGURE 2—Bottom-hole assembly that breaks off the core into 6-inch increments.

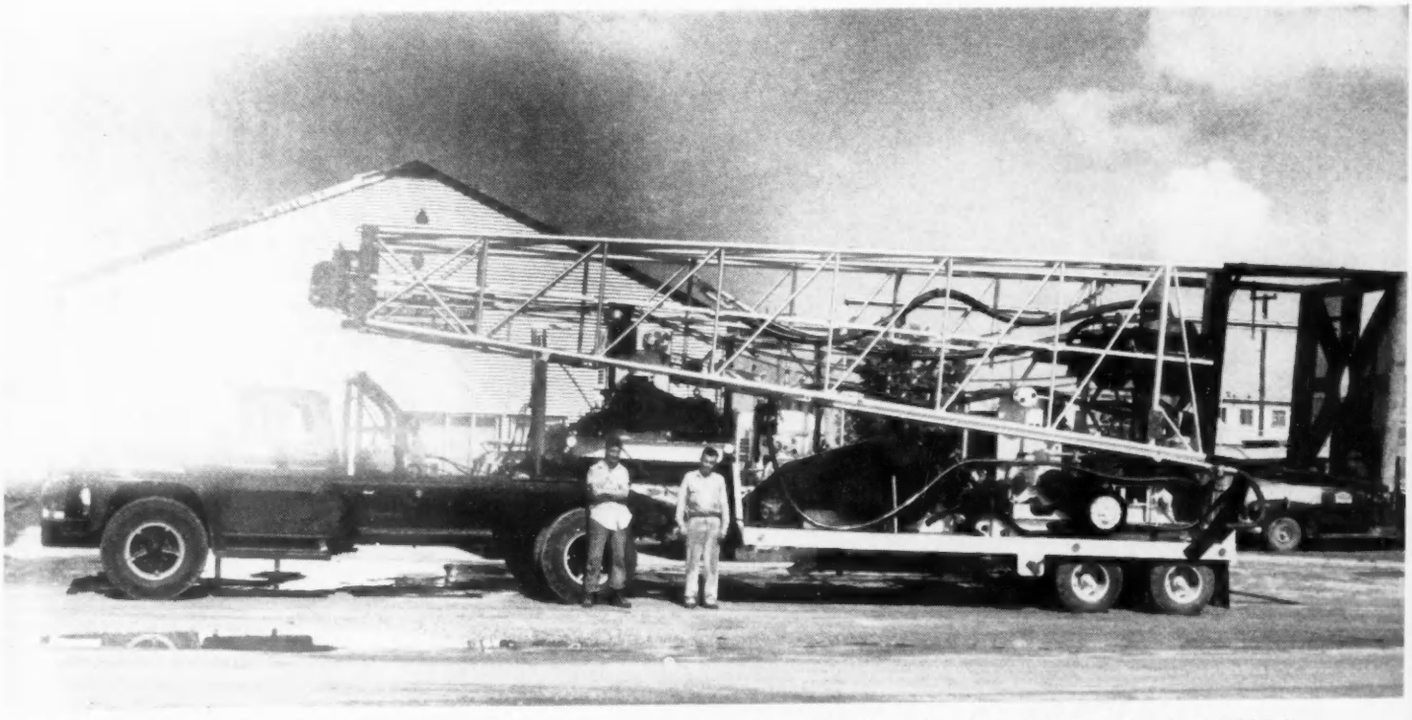


FIGURE 3—Portable trailer mounted rig shown in transported position. Rig is equipped to drill to a depth of 5,000 feet.

FIGURE 4—The rig while drilling on location.

ment may be run through the core tube.

Exploration and development drilling method. This new drilling technique can be used as a valuable tool for future exploration activity in finding hydrocarbon deposits and/or other minerals. It is also believed that after further operational experience, this new method should prove valuable to development drilling.

Exploration. Geological aspects which may be evaluated with this method are:

- *Structure*
  1. Dip and direction of every formation in the entire lithological section may be ascertained.
  2. Faulting may be detected.
  3. Multiple tests can determine if any section or formation is thinning or thickening.
  4. Multiple tests can detect any real change in lithology or paleontology (facies change).
  5. Porosity and permeability of possible pays and gradations from test to test can be determined.
  6. Any cross-bedding, unconformities, truncations, or overlaps can be detected.

- *Shoreline conditions*
  1. Measurement can be made of the ratio of sand to clay and gradation of particle size to determine if the seas were advancing or receding when particular formations were being sedimented, and thereby determine the direction to move for a favorable shoreline condition.
  2. Facies change can be located by inspection of "full section" cores, and comparison with nearby tests can be made.
  3. Fossils in the cores can be used to compare with nearby tests to indicate the ancient sea condition for interesting formations at each test and the gradation from test to test.

- *Porosity traps.* The full section is always cored. The percent of porosity in any possible pay formation can be measured to determine if it is increasing or decreasing from test to test, from sand to limestone, and from "cementation" or "solution."

- *Sand lenses*
  1. All sands are automatically

cored, and the direction of sand thickening, thinning or presence can be determined.

2. Magnetic orientation of the core, plus sand grain examination, can determine direction of the lense axis.

- *Lithology evaluation.* The 100 percent core recovery offers a detailed picture of each formation penetrated. Cuttings evaluated from conventional drills often are mixed with cavings, mud erosion, etc., which lends to incomplete or difficult determination of the true lithological nature and/or interval.
- *Geophysical anomalies of questionable nature.* Cost of core test and geophysical "detailing" of anomalies may be reduced.
- *Exploration of areas not adapted to geophysical exploration or evaluation.*

1. Areas wherein surface or subsurface conditions make evaluation with geophysical methods impossible, inaccurate, or too expensive may be studied.
2. Areas where the structural relief is less than the accepted error (resolving power) of geophysics may be explored.

Production. The adaptability of this technique to development drilling is discussed below.

- *Drillstem testing.* Internal flush drillstem permits drillstem testing of oil shows by the drilling crew. Since cuttings are not present in the hole annulus with this method of drilling, a drillstem test can readily be taken. Drillstem tests may be run with or without a packer. When a zone is to be drillstem tested, a "Tee" is inserted in the core tube at the power swivel and the well is swabbed in (Figure 5).

  The main pump stands by to pump heavy mud into the pipe annulus, or into the hole annulus, or both, should the well develop excessive pressure. If necessary, the packer (if used) can be unseated and the drill pipe rotated. When a packer is not used, the pipe may be rotated continuously.

  A relatively heavy mud is maintained in the hole annulus to counteract any bottom hole pressure build-up. If this hydrostatic head is not sufficient, a pump may be used to build up the pressure. The pipe annulus is connected to the pump, and the core tube is left open for conducting the drillstem test with a normal swabbing technique. After the test is run, reverse circulations, down the tubular annulus, is started and drilling can be resumed.

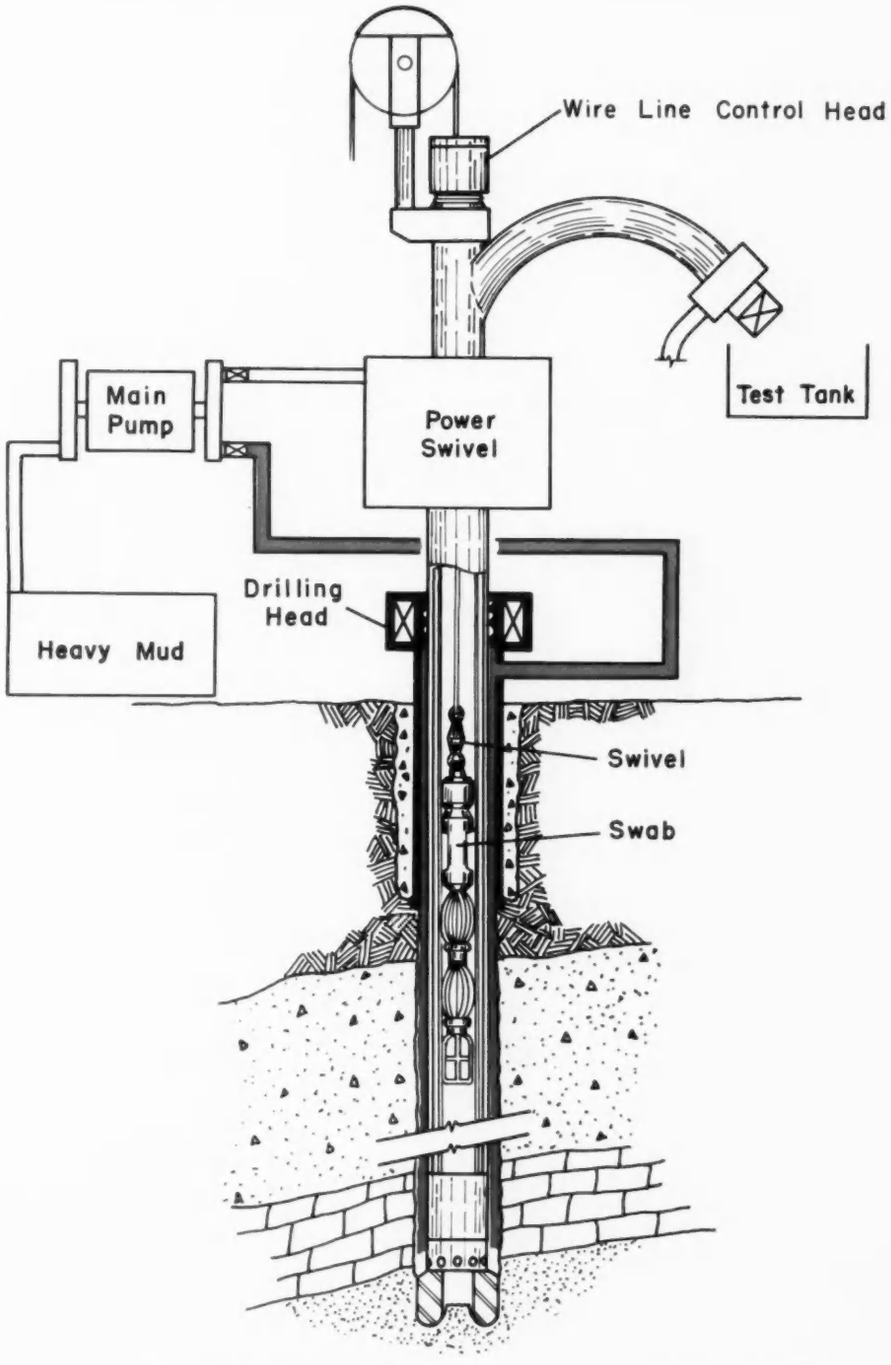


FIGURE 5—A drillstem test may be taken without the use of third party services. Here is shown a schematic of a DST operation while using this new drilling technique.

- *Casing setting depths.* Accurate information about the lithology and depths of competent formations for setting casing can be obtained because of the true evaluation of the penetrated section.
- *Small diameter holes and tubingless completions.* With these operations expanding, this drilling technique permits a true evaluation of porosity and permeability of the full pay section, substan-

tially a 100 percent recovery, and determines the best perforating or acidizing depths. Small holes further enhance the economics of this type of completion; less mud, less cement, and less and smaller tubular products. Small diameter holes also minimize caving.

- *Penetration rates.* With increased experience, penetration rate may be comparable to that of present practices. The method has the advantage of a clean hole bottom (no cuttings) due to the hole cleaning efficiency of "reverse circulation." A further advantage is the possibility of high rpm (up to 500) when using diamond or blade bits. The most difficult part of the hole to cut is the center, which in this method is left uncut (the core).
- *Reservoir evaluation.* The entire section is cored in each well so a true reservoir evaluation of the field can be calculated.

Drilling practices. After the rig is moved onto location, surface hole is drilled with conventional circulation and a full hole bit. Seven-inch or similar size surface casing is set and cemented. A drilling head is made up on the surface casing, packing off the hole annulus to the drill pipe (Figure 1).

A special mud may be pumped into the hole annulus, and a constant pressure can be maintained by a pump tied into the system. This hole annulus mud, should have lubricating properties, should prevent hydration of shales, should form a thin tough filter cake, and should be somewhat heavier than the circulating mud. The pressure may be varied to maintain a satisfactory minimum pressure condition at the drilling head.

The bit is made up on the drill pipe and run into the hole. The traveling rotary swivel is attached to the drill pipe, and circulation and drilling is commenced.

The pipe is turned at a selected rate between 40 and 500 rpm with a selected weight of 2,000-10,000 pounds. As the hole is drilled, pipe is added to the string in the conventional manner. The pipe is made-up and broken-out with the power swivel.

This type of drilling technique offers:

- Fast rotation
- Continuous determination of optimum weight on the bit and optimum rotary speed
- Low labor costs—three men per crew

What they say about this new drilling

Preston L. Moore—Assistant Professor, School of Petroleum Engineering, The University of Oklahoma: "The procedure outlined for coring by reverse circulation is interesting and appears to offer a potentially good method for the complete examination of certain types of underground formations. Formation type is mentioned because it is believed, as currently outlined, this method of coring and drilling would be more adaptable for work in hard, stable and normal pressure formations. The economic application of this technique for the sole purpose of being competitive with or less than normal drilling costs is believed possible in shallow drilling (above 2,500 feet) only.

"For deeper drilling it will be difficult to compete with conventional techniques, because

1. Bit weight that can be applied will be limited.
2. Pipe running time will be slower.
3. Torque requirements will necessitate more power for rotation than can be supplied with the power swivel.
4. Drilling rates will never be as fast as can be accomplished with good conventional practices.

"There is no doubt that advantages in exploration can be gained through the use of this method.

"The rig equipment and method of operation offer a novel approach to drilling with less surface power. This within itself is encouraging and is an approach that should be followed even in conventional drilling. More information is needed relative to the support of the heavier mud in the hole-pipe annulus. When circulating this may be possible; however, problems are introduced when circulation is stopped or when removing pipe to change bits.

"The claims made for this technique in drilling practices such as fast rotation and optimum weights and rotary speeds are important only insofar as they make this a faster method of drilling, which at this point is questionable. Less horsepower requirements and lower circulation rates are attractive features. It is believed that hole stability will be more of a problem with this technique than with conventional drilling.

"In summary, the operators are to be congratulated on perfecting this technique to its current level. Its future in full scale operations will have to be determined; however, it should be remembered that most people would have doubted that the current stage of development could have been accomplished."

Harry McClain—President, United States Sulphur Corporation: "This new method of drilling should certainly improve our evaluation of sulfur, hydrocarbons or other mineral reserves. It should also be a means of economically drilling areas heretofore believed to be uneconomical. Loss of circulation and a lack of full recovery of cored intervals have been a hindrance in our drilling program. If this new technique, which uses dual drill pipe, reverse circulation and electric swivel, is successful in recovering 100 percent of the lithology penetrated, a new era in the exploration and production phase of the oil and mineral industry could be realized."

Wayne E. Glenn—General Manager, Production Department, Continental Oil Company: "Continental has experimented with the Strato Drill in two wells. The equipment was successful in recovering 100 percent of the core cut. We believe that its successful development will be of considerable benefit anytime it is desirable to core a long section. Certainly, it will be useful in locating

- Less mud volume
- Mud pump horsepower reduction
- In case of a caved hole, the circulation is not stopped. There are no couplings on the outside flush drill pipe and there is no kelly joint. Therefore, if rotation is possible, it is likely that drilling out can be done with the power swivel. The probability of caving is reduced because
  (1) no circulation exists in the hole annulus,
  (2) special mud is designed to prevent shale hydration and
  (3) because of the small diameter bore hole.
- Hole is kept clean by reverse circulation, resulting in no rework of old cuttings, hence fast digging and reduced shock results on the bit bearings and drill pipe.
- Hole is almost filled with drill pipe, reducing crooked hole tendencies. No possibility of "key-seating" exists.
- No need for logging or sidewall coring. If logging of any section is desired, for comparison, a sonde can be lowered through the drill pipe with the drill pipe being raised only enough to expose the interesting section which is normally the "sand" just drilled.
- A valid technique for determining the value of the well prior to setting casing.
- The need for less torque on drill pipe, therefore less rotary horsepower.

Use of dual drill pipe. Dual drill pipe increases rigidity, lessens pipe whip, lowers the torque, straightens hole, and reduces cavings.

For efficiency, the pipe was designed to obtain substantially the same mud velocities in both channels. Mud velocities in present conventional drills are several times higher in the drill pipe than in the hole annulus. It is necessary, of course, to keep mud velocity in the hole annulus, when conventionally drilling, to efficiently remove the cuttings. This requires high velocity in the drill pipe, resulting in high friction losses. The friction loss in the dual pipe method is about 1/40 of that in conventional methods.

To maintain a constant velocity in the return mud stream, pump requirements vary considerably between conventional and dual string drill pipe. Table 1 shows a comparative value of the respective circulation requirements. When a washout interval is encountered (Figure 6), the large cuttings will be suspended in the enlarged area where the velocity is materially lessened. If circulation should be interrupted, these large cuttings will settle around the drill pipe. This condition is magnified with the use of air as the circulatory medium.

Because of the rigidity of this type of tubular drill string, high rotation speeds may be obtained. Thus, the use of drag, diamond or carbide bits can be used to advantage. These types of bits lend themselves to faster penetration with faster speeds provided proper cooling is maintained.

Dual drill pipe will minimize loss of mud to "thief" zones. In a sense, the drill pipe is used as casing and eliminates the circulating fluid from contacting these zones. Consequently, the only mud lost to the "thief" zones is limited to the amount lost while drilling through the zone. The special mud in the hole annulus may incorporate loss-circulation material.

Full hole stabilizers are used with the dual drill pipe to further improve its stability in crooked hole drilling areas. These stabilizers are equipped with carbide cutting tips on the upper surfaces of the stabilizers, enabling drilling out of the hole if caving conditions should occur.

If a loss-of-circulation-zone presents continuing difficulties, cement may be spotted and properly squeezed without pulling the drill pipe.

How are blowout conditions combatted? If a high-pressure zone, hydrocarbons or water, is encountered while drilling, and starts to flow out of the core tube, the following practices should be followed:

1. Check hole annulus as to pressure build-up on surface gage. If the hydrostatic head of the annular mud is insufficient to contain the bottom hole pressure, the main pump is switched to heavy mud (held in standby) and this heavy mud is pumped into the tubular annulus and the hole annulus. When the flow is diminished, the valve on the core tube (Figure 1) may be closed, or heavy mud may be pumped into the core tube.

2. A set of ram type preventers may be inserted in the well head assembly to control the well when the pipe is out of the hole.

Savings on drilling mud. Because of the control at the well head for blowout conditions, together with relatively heavy mud in the hole annulus, the lighter weight drilling muds may be used. This results in less pressure on the pay formation, hence less water intrusion or "mud blocking" of the pay zone, and "lost-circulation" is minimized. The cost per barrel of this mud is less and, due to small hole size, less mud is used, thus reducing the over-all mud costs. Since lighter mud weight can be used, faster penetration may be appreciable.

technique . . .

stratigraphic traps and in geophysical and geological research. If the equipment can be perfected to compete, on an economic basis, with conventional drilling including cost of hole examination, it has a great future."

Frank C. Roper—Independent Geologist, Houston, and Joe E. Smith—Independent Geologist, Beaumont, Texas: "As independent geologists and producers, many valuable uses of this new drilling technique can be realized. If this type of continuous drilling-coring proves successful economically, then the scientific advantages are innumerable and unlimited. A few outstanding advantages are: complete formation log; a complete set of cores for evaluating all types of analysis—chemical, paleontological, and lithological; any oil or gas would be detected as soon as encountered by the drill bit, and the smallest lenses or pinch-out could be observed; any show or saturated formation could be drillstem tested without pulling pipe from the hole; dip of formation can be ascertained; complete cores would render information in picking faults, either by loss of section, abrupt formation breaks, Slickensides or other fault type phenomena."

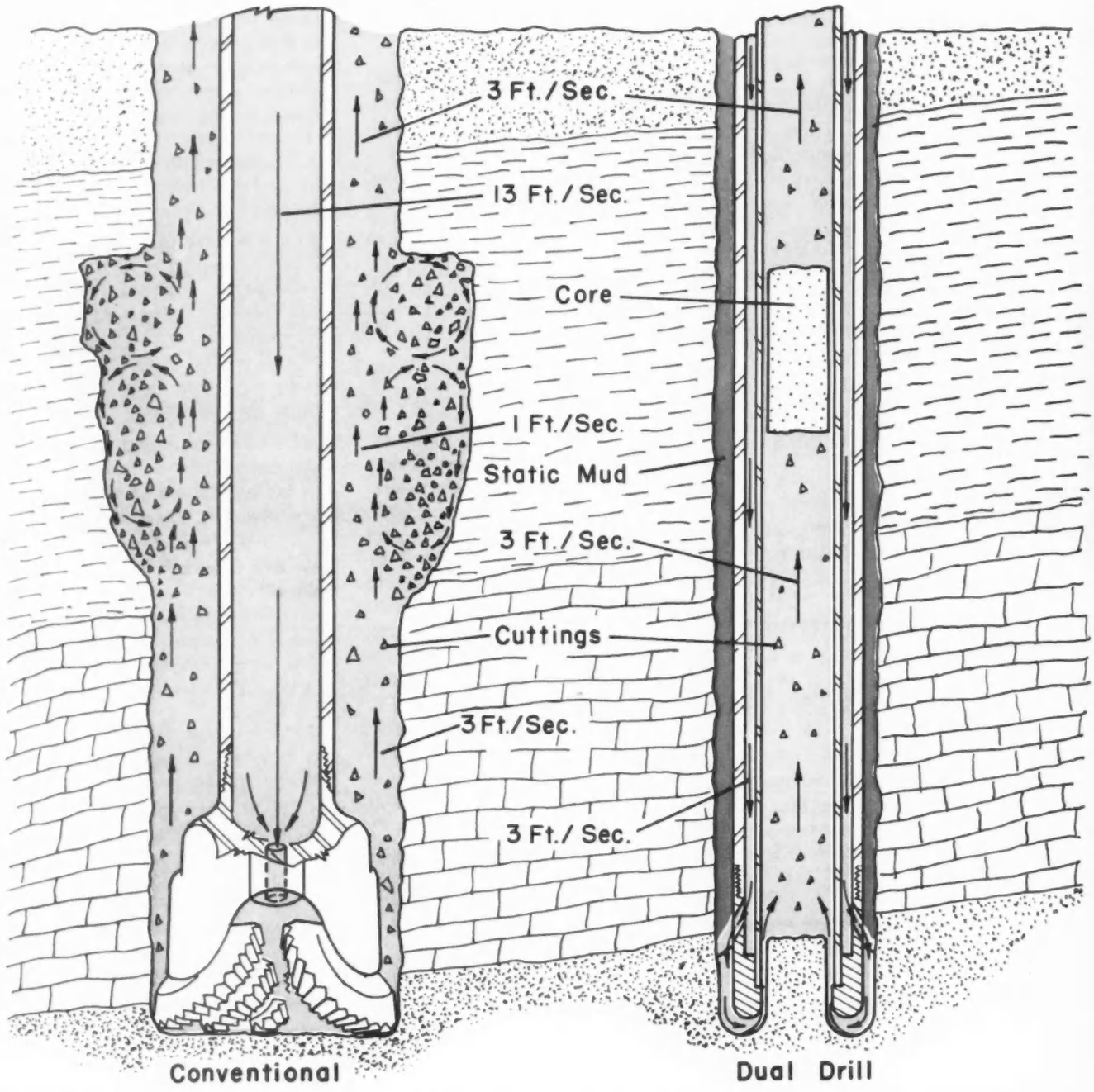


FIGURE 6—Schematic drawing showing differences in circulation between a conventional drill and the new dual pipe drill. Mud velocity vectors are drawn to scale. Note shale cavity in the conventionally drilled hole, and the pile-up of cuttings in this cavity due to much lower velocity in the scavenger mud stream. Upon stopping the pump, the cuttings will have a tendency to settle out around drill pipe or bit. Also note that the large cuttings are not able to rise above shale cavity.

What drilling practices can be learned from a continuous core? The hardness and drillability of the stratum can be determined from cores that are continuously being retrieved, and this indicates to the driller the optimum bit weight and rotational speed.

By inspecting the recovered core, the driller determines the approximate rate of penetration that should be obtained in that formation. If he is not drilling at that penetration rate, he assumes that the bit is worn and should be replaced.

Also the degree of smoothness of threads on the core will indicate the condition of the bit. This evaluation of bit condition should eliminate the pulling of a good bit and the running of a worn out bit and should result in fewer round trips of the pipe, and maximum footage per dollar from each bit.

Evaluation of cores of previously drilled nearby tests will permit the selection of the best bit for each specific lithological interval.

Other applications for this drilling technique include:

- Continuous coring which will disclose shallow strata of valuable minerals other than oil or gas
- Geophysical drilling
- Irrigation water well drilling
- Uranium coring —**The End**

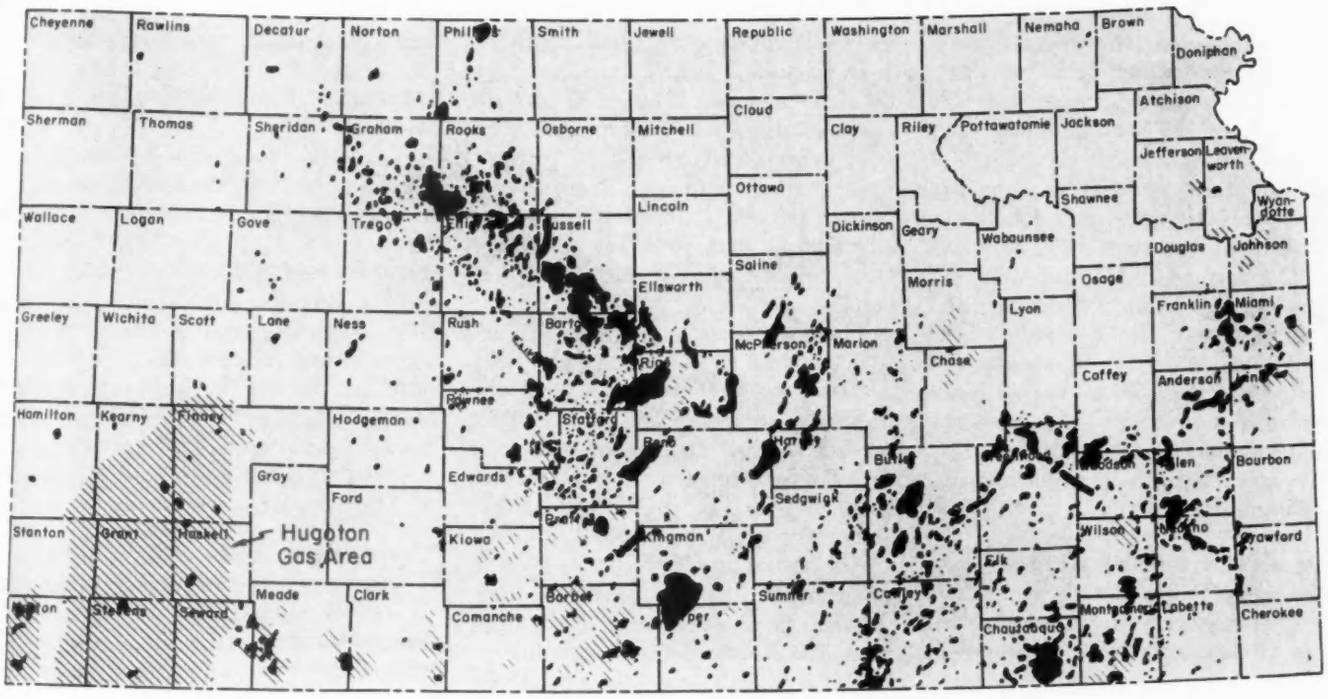


FIGURE 1—Of 105 counties in Kansas, a total of 84 have produced oil and/or gas.

How major geologic features developed in Kansas

Several regional unconformities separate oil-bearing Paleozoic beds; erosion of formations has strong bearing on oil and gas deposits

By J. M. Jewett, Senior Geologist
State Geological Survey of Kansas, Lawrence

REGIONAL GEOLOGY and structural and stratigraphic history of Kansas can best be analyzed through a thorough study of depositional and erosional cycles which took place during the Paleozoic era. Widespread oil and gas production throughout the state has made possible exhaustive studies of its geologic history. There is some rare production from the pre-Cambrian; several major regional unconformities separate oil-bearing Paleozoic beds; and the youngest oil and gas bearing beds are early Permian in age. Weathering and erosion of some formations has much to do with their becoming oil reservoirs; many Arbuckle pools are in combined stratigraphic-structural traps.

The geology of Kansas is relatively simple. In Kansas there are no deep basins nor complex structures that are intricately folded and faulted. The sedimentary cover on crystalline basement rocks is thin, little more than 500 feet thick at a place in northeast Kansas and believed to be less than 10,000 feet in the southwest part of the state where it is thickest.

Major structures, whose growth and subsequent history are linked with development of oil and gas pools in Kansas were formed chiefly at two comparatively short periods of pronounced but mild crustal unrest. These times, hardly to be called orogenic, occurred near the end of the Devonian, and at about the close of Early Pennsylvanian time. Changes in over-all rock arrangement, especially regional uplift and tilting at various times, have taken part in causing present accumulations of hydrocarbons. Eastward tilting that was significant, geologically speaking, took place only a short time ago. The degree to which Kansas rocks, especially the older ones, have been moved vertically as the country subsided and was elevated, is great; however, rock layers remain in positions that are close to horizontal. Dips of beds in both subsurface and surface commonly are measured in small fractions of a degree. Only very locally, e.g., in places along one of the flanks of the Nemaha Anticline, are dips of more than a few degrees believed to exist.

Oil and gas fields are widespread in Kansas (Figure 1). There are in the state 105 counties; a total of 84 have produced oil or gas. Current annual production of oil is about 125 million barrels, and gas production amounts to nearly 600 billion cubic feet.

The relatively simple arrangment of large divisions of rocks in Kansas

is shown in Figure 2, a generalized areal geologic map of the state and a very much simplified cross section. The rocks themselves coveniently are divided into 7 great divisions: (1) basement rocks, ancient crystallines of pre-Cambrian age which nowhere are buried very deeply, (2) Cambrian and Ordovician rocks, (3) Silurian and Devonian, (4) Mississippian, (5) Pennsylvanian and Permian, (6) those of Mesozoic age, almost all Cretaceous and (7) Tertiary and Pleistocene. Because of regional unconformities and individual tectonic arrangements, these divisions are stratigraphic-structural units meriting individual discussion.

The basement of Kansas (pre-Cambrian) consist mainly of granite, schist and gneiss, but several other types of igneous and metamorphic rocks have been identified (Farquhar, 1957). Some arkoses and fractured quartzites in central Kansas are containers of commercial quantities of oil and gas; this is a decidedly exceptional condition, inasmuch as pre-Cambrian rocks generally are entirely devoid of these fuels. Figure 3 shows configuration of the pre-Cambrian floor, with a 500-foot contour interval. On this scale only the Central Kansas Uplift and Nemaha Anticline, among major generalized structures, stand out prominently as positive elements.

All Cambrian rocks shown in Kansas are of *late* Cambrian age. Older Ordovician and most of the Cambrian beds are known commonly as "Arbuckle," a term applied more properly to an assemblage that contains a more restricted Cambrian section. The Simpson Group (including St. Peter Sandstone), Viola Limestone and Maquoketa (Sylvan) Shale are younger Ordovician deposits. Those of Silurian and Devonian age make up what is called "Hunton." "Mississippi lime" is the term frequently applied to most Mississippian age rocks. The Pennsylvanian contains many officially and unofficially designated units whose names are heard in oil fields. Early Permian rocks are the youngest that bear oil and gas in Kansas, and in this respect they are important almost solely because of the great Hugoton gas pool (Figure 1). These and others of the seven rock divisions are mentioned in following parts of this paper in which accumulation of the sediments and their tectonics are discussed briefly.

In an area of nearly flat-lying rocks divided by many regional unconformities, time relationships and physical conditions can best be understood through reference to great erosional surfaces. Reference is made to the Kansas part of a few extensive erosional surface including the present land surface.

The pre-Cambrian surface (Figure 3) is not of pre-Cambrian age and probably no part is as it was at the beginning of Cambrian time. A part was undergoing erosion as recently as late Pennsylvanian time. As a datum plane it is by far less useful than are some higher unconformities.

Accumulation of enduring sediments started in late Cambrian time. At first there were some clastics but soon calcareous deposits dominated. After a few thousand feet of Cambrian and lower Ordovician beds were laid down, erosion set in; the thickness of limestone or dolomite removed from a newly formed "high" in northeast Kansas was greater than from nearby areas. Southeast Kansas was to a degree a basinal area with a larger thickness of sediments preserved than in adjacent areas. These conditions have given us the two oldest named structures in Kansas, the Northeast Nebraska Arch and the Ozark Basin. After the later Ordovician rocks known as Simpson, Viola, and Maquoketa, and some Devonian and Silurian sediments had accumulated under waters of seas that transgressed and regressed an undetermined number of times, crustal unrest again brought about consequential changes in Kansas.

Pre-Mississippian structures. Figure 4 represents the inferred distribution of rocks on the surface next below the Chattanooga shale, which is of late Devonian or early Mississippian age, or where there is no Chattanooga below Mississippian limestone. It is the surface that was buried under late Devonian or early Mississippian sediment. The outcrop pattern conforms to large geologic structures that previously had been elevated and eroded. In the southeastern part of the state, Simpson rocks cropped out as a border around and dipping away from a large area of Arbuckle rocks. To the north, a large expanse of Devonian sediments was preserved from erosion in a basinal area. To the northwest there were areas of Arbuckle exposures flanked by Simpson. Pre-Cambrian rocks were exposed in the highest part of the uplift there.

Because of conditions, as shown in Figure 4, we may designate pre-Mississippian structures as shown in Figure 5. John L. Rich (1933) called the combined Chautauqua and ancestrial Barton Arch (now called Ellis) the Central Kansas Arch. These structural elements give to the state its ancient structural grain. Many Kansas oil fields lie above deeply buried anticlinal structures that had their origin before the time of Mississippian rock accumulation.

Chautauqua Arch. Figure 4 shows a broad area of "Arbuckle" outcrop in the southeast part of the state, flanked on the northwest by Simpson beds. This region represents the southwestern extension of the Ozark Uplift, and has been named Chautauqua Arch.

North Kansas Basin. The north Kansas structure is designated a basin chiefly because of adjacent "highs". The lesser thickness of pre-Mississippian rocks in the "high" areas probably is to a greater extent due to differential erosion than to non-deposition.

Ellis Arch. The Ellis Arch was named and designated as distinct from the younger Barton Arch (or Central Kansas Uplift) chiefly because of the strike of anticlinal folds in pre-Pennsylvanian rocks that differ materially from the axis of the more recent uplift. These folds are interpreted as pre-Mississippian in age. They are aligned with fold of the Chautauqua Arch and seem best interpreted as older in origin than other structural features of the Central Kansas area. The conjectural distribution of pre-Mississippian rocks shown on Figure 4 is in accordance with interpretations of D. F. Merriam, of the Kansas Geological Survey, and is modified from Hugh McClelland (1930) and Moore and Jewett (1942).

Southwest Kansas Basin. Southwest of the Ellis Arch and west of the Chautauqua Arch is a basinal area of pre-Mississippian data which is known as the Southwest Kansas Basin. It is now believed that there is no "Hunton" in that part of Kansas, but a thick Ordovician section including Simp-

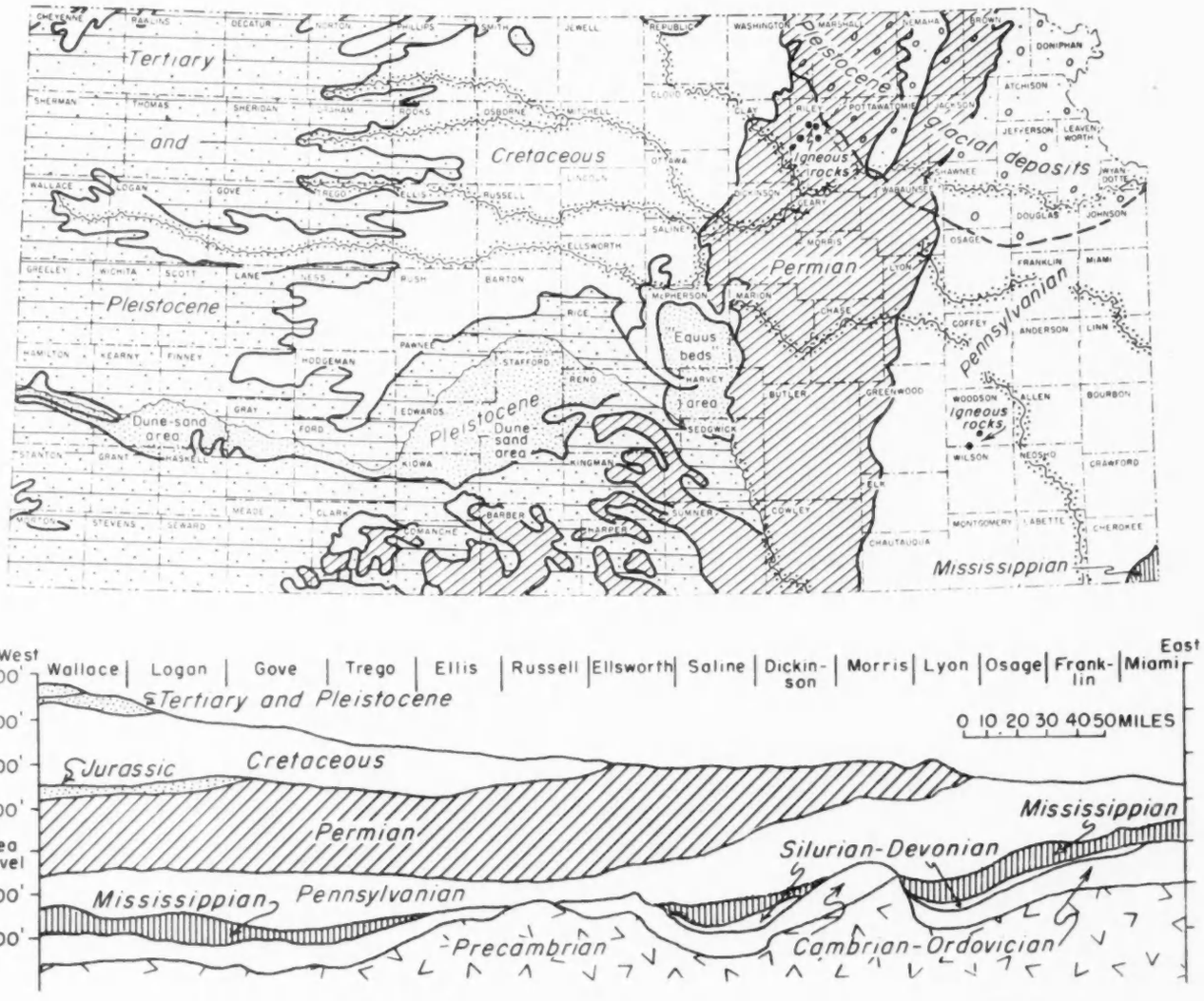


FIGURE 2—Areal geologic map and highly simplified cross section of Kansas show major rock units and structural patterns.

son and Viola, as well as the presence of adjacent uplifted areas, warrant designation as basin.

Post - Mississippian - pre - Middle Pennsylvanian structures. Mississippian sediments covered the surface whose areal geology is represented in Figure 4. At the end of Mississippian time, large quantities of rock material were once again being eroded from most of Kansas. Erosion probably affected large areas at several times during the period but pronounced warping did not take place. In southwestern Kansas sedimentation ceased only slightly, if at all, during the transitional period from Mississippian to Pennsylvanian. However, it was not until well after the start of Pennsylvanian time that enduring sediments again were deposited in most parts of the state. It was apparently at about the end of Early Pennsylvanian time that crustal movements of great consequence began anew.

Figure 6 is a map showing distribution of rocks on a surface next below Pennsylvanian rocks. It is not a pre-Pennsylvanian areal geologic map; it is a map of a surface, parts of which were buried, hence preserved, at different times but all within Pennsylvanian time. In southwestern Kansas, burial took place in the early part of the period; parts of the Barton Arch and of the Nemaha Anticline were not completely buried until late in Pennsylvanian time. In most of Kansas there are no Lower or lower-Middle Pennsylvanian rocks.

Mississippian rocks that had been deposited over the pre-Mississippian surface shown in Figure 4 remain in most parts of the state, but pre-Cambrian rocks bordered by pre-Mississippian formations were exposed on the higher parts of the Nemaha Anticline and the Central Kansas Uplift. That Arbuckle rocks in the central Kansas area were subjected to weathering and erosion for a long time had a great deal to do with their becoming reservoirs for oil. Many pools are in combined stratigraphic-structural traps.

Based on conditions represented in Figure 6, post-Mississippian structural provinces are designated (Figure 7). They are pre-late-Pennsylvanian and like other structures should be thought of as having an upper and lower time boundary. These structural provinces, actually areas below which there are deeply buried structures of importance, serve very well as petroliferous provinces and have been so designated. The structures that give names to the surface areas would never have been known without drilling, for they are deeply buried.

As provinces in Kansas, either structural or petroliferous, the names

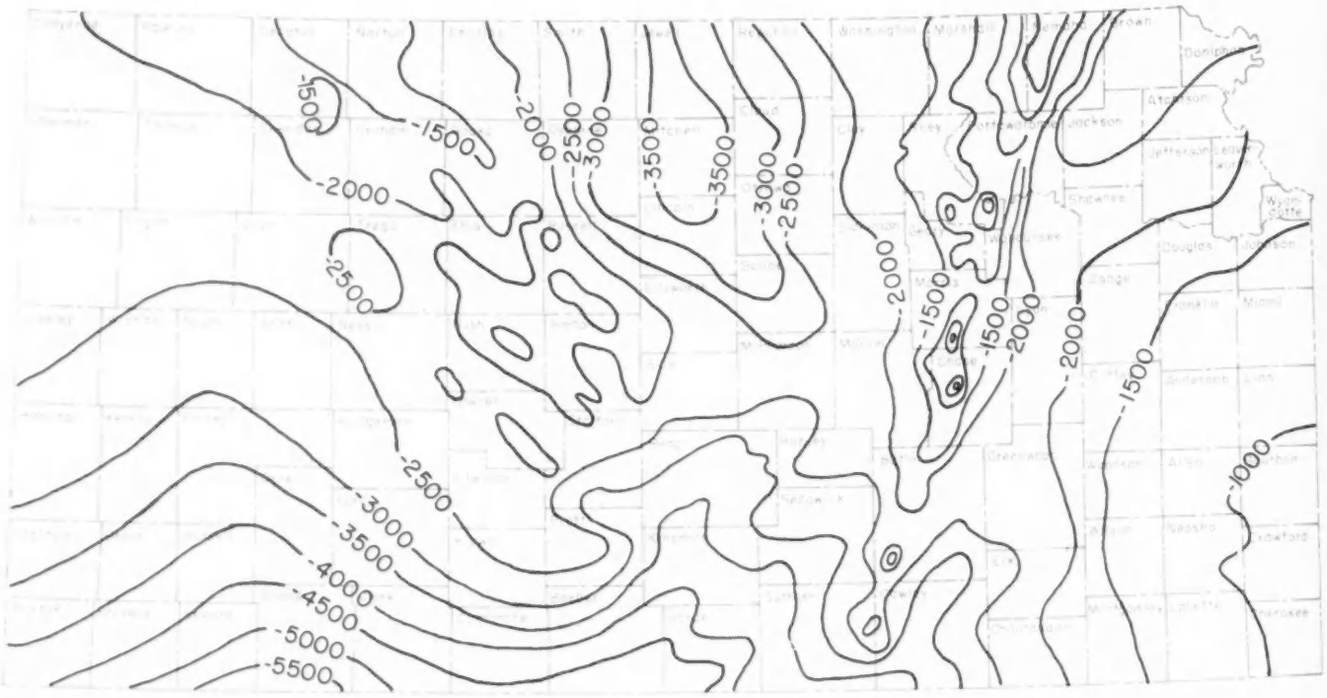


FIGURE 3—Pre-Cambrian surface of Kansas. This surface, however, is not of pre-Cambrian age and probably no part is as it was at the start of Cambrian time. Part was undergoing erosion as recently as late Pennsylvanian time.

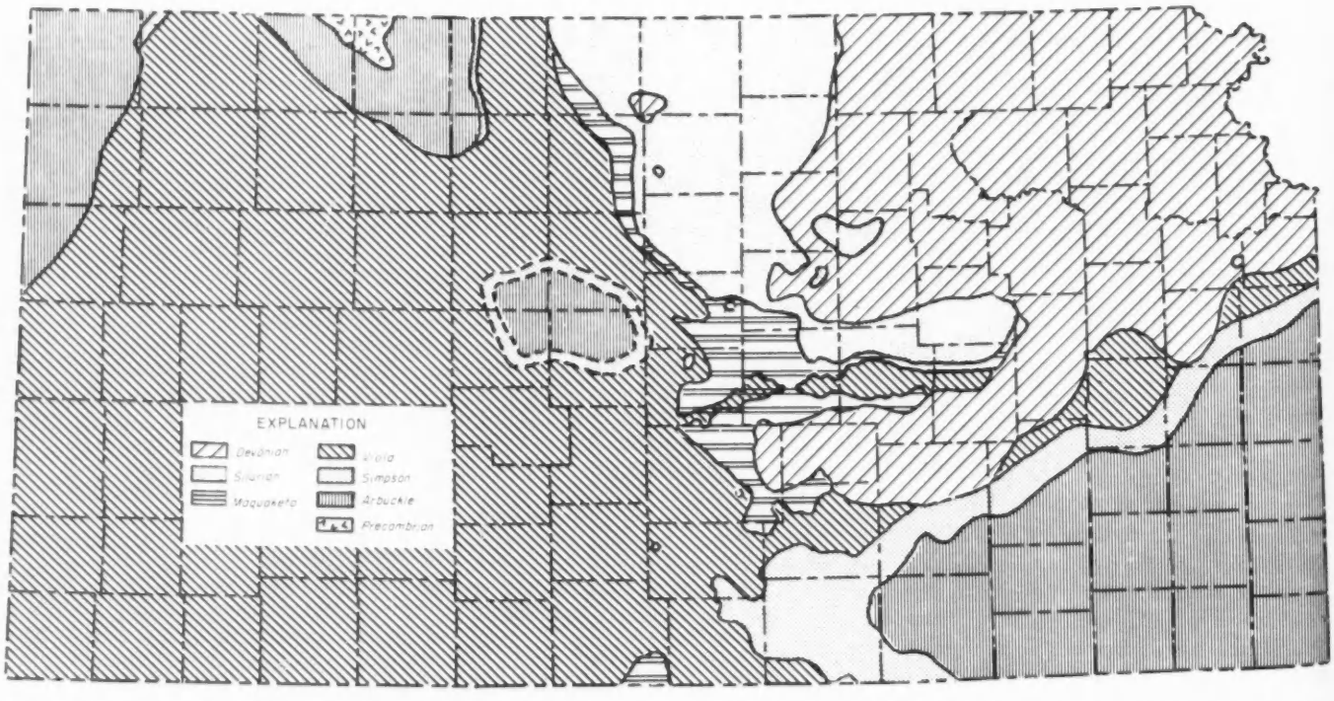


FIGURE 4—Inferred distribution of surface rocks directly below the Chattanooga shale (late Devonian or early Mississippian) or where no Chattanooga occurs below Mississippian limestone. This truncated erosion surface was buried under late Devonian or early Mississippian sediments. Broad area of "Arbuckle" outcrop shows in southeast, flanked by Simpson beds.

in Figure 7 are well known. Only brief comments are needed here.

Nemaha Anticline. The Nemaha Anticline, whose buried crystalline core is often referred to as the Nemaha mountains or granite ridge, trends south-southwest across Kansas from Nemaha County to Sumner County. Mississippian and older rocks are tilted and eroded on the flanks of this uplift, which is much steeper in most places along its length on the east than on the west. Pennsylvanian sediments on the anticline overlap rocks ranging in age from pre-Cambrian to Mississippian. Pennsylvanian strata lie upon pre-Cambrian rocks in a belt extending in a northeastward trending direction from a point in T. 11 S., R. 10 E., and in some areas farther south. The extreme northern part of the ridge of pre-Cambrian granite in the Nemaha Anticline was not covered by enduring Pennsyl-

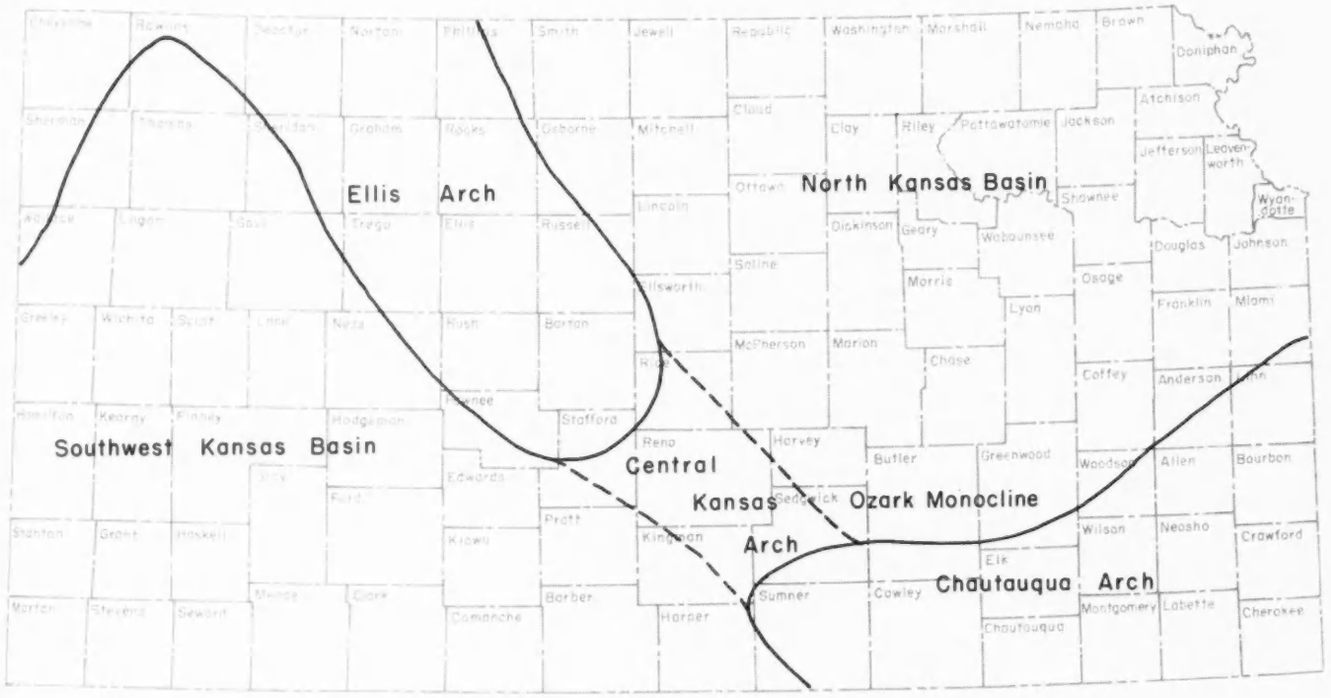


FIGURE 5—Pre-Mississippian regional structures of Kansas. Many oil fields lie above deeply buried anticlines.

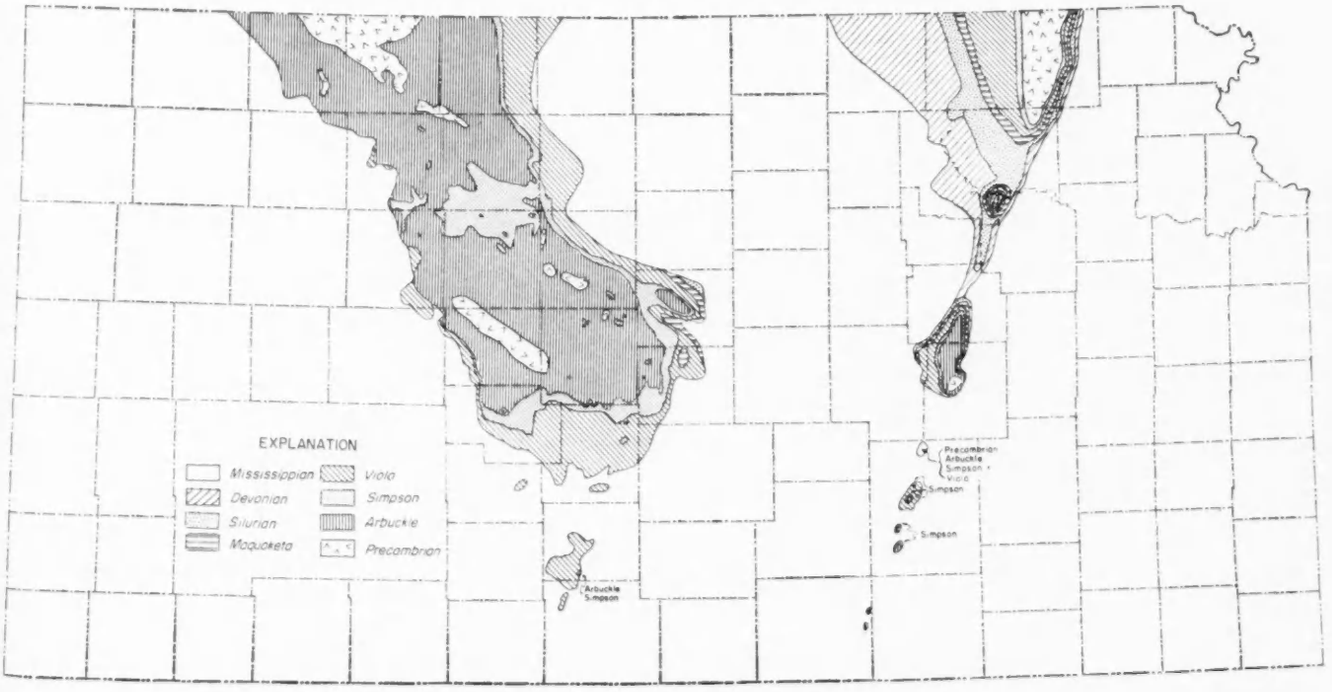


FIGURE 6—Truncated surface shows rock distribution next below Pennsylvanian strata. This map differs from a pre-Pennsylvanian map; parts of this surface were buried at different times during Pennsylvanian time. Burial occurred early in the period in southwest Kansas; parts of the Barton Arch and the Nemaha Ridge were not wholly buried until late Pennsylvanian times.

vanian sediments until Virgilian time. Older Pennsylvanian beds overlap pre-Cambrian and Paleozoic rocks along the southern part of the axis of the ridge. In general, pre-Cambrian rocks lie about 2,000-feet lower, a short distance east of the uplift than on its axis.

The famous El Dorado and Augusta oil fields (Butler County) lie in and on the flanks of the Nemaha Anticline. In those fields the chief producing zone is along the beveled pre-Pennsylvanian surface cut in Ordovician rocks. Several other pools, mostly on the flanks of the uplift in its southern part, have yielded great quantities of oil from Ordovician, Mississippian and Pennsylvanian strata.

Forest City and Cherokee Basins. Separation of the area east of the Nemaha Anitcline is established by long usage and is of some convenience. The separating Bourbon Arch is a low structure expressed in sub-Pennsylvanian rocks. Seemingly enduring Pennsylvanian sediments accumulated at an earlier date in the Forest City Basin than in the Cher-

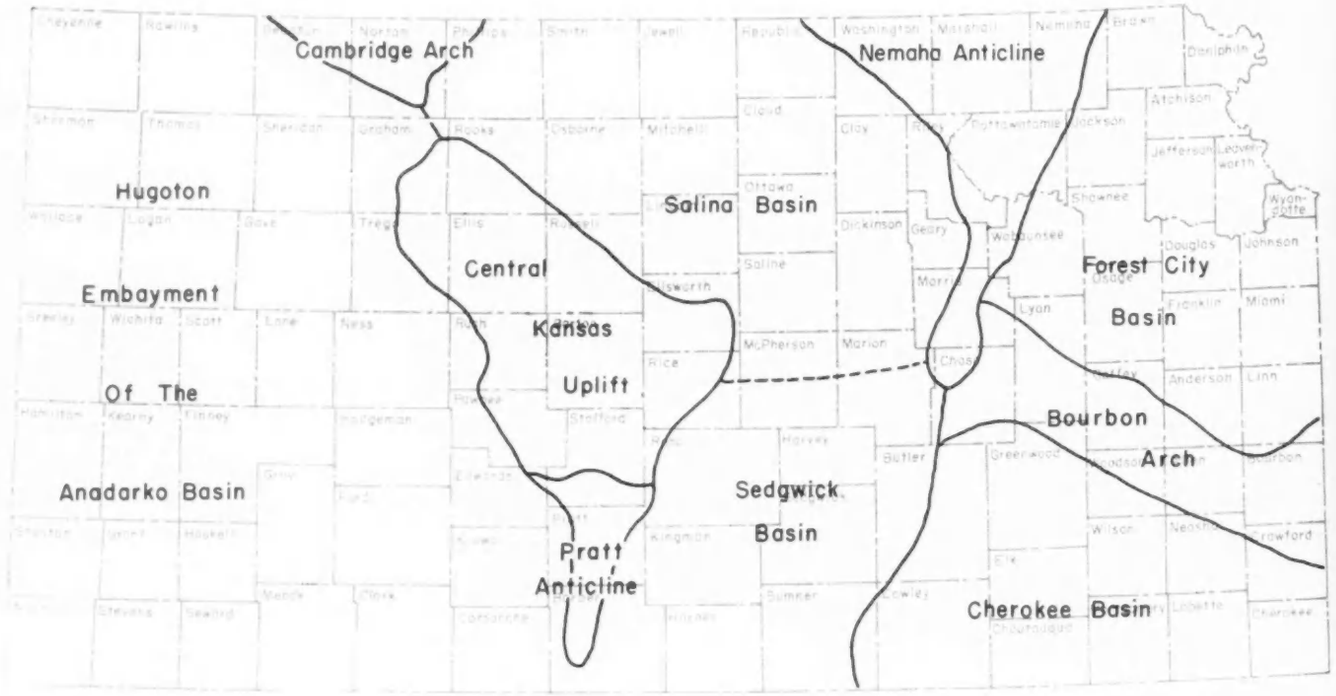


FIGURE 7—Post-Mississippian structural provinces of Kansas. Regional structures are pre-late-Pennsylvanian and have limited upper and lower time boundaries as regards origin. This analysis delineates petroliferous provinces of Kansas.

okee Basin. Ordovician, Mississippian, and Pennsylvanian rocks yield oil and gas in the two basins. Production from Pennsylvanian "shoestring sands" has been of greatest importance. Several anticlinal folds, paralleling the Nemaha Uplift contain important oil pools.

Salina and Sedgwick Basins. General nature of geologic structures and production in oil fields as well as a low pre-Pennsylvanian dividing "high", shown through the thinning of Mississippian rocks, warrant separation of two basinal areas between the Central Kansas Uplift and the Nemaha Anticline. There are many highly prolific oil pools, especially in the Sedgwick Basin, where geologic conditions are more complex than any known in the Salina Basin.

Central Kansas Uplift. Similar to the Nemaha Anticline, the Central Kansas Uplift (or Barton Arch) is judged to be of post-Mississippian origin because of the presence of tilted and erosion-truncated Mississippian strata on the flanks of the uplift and the absence of the Mississippian in the central high parts of the elevated area. Also, as in the Nemaha Anticline, older Pennsylvanian rocks are missing from the higher parts. Largely for convenience, as a matter of crossing state lines, the name Cambridge Arch is sometimes applied to the northernmost part of the Central Kansas Uplift. Pratt Anticline is a name sometimes used for the southern part (Figure 5). Hundreds of oil fields in the central Kansas area produce from stratigraphic and structural traps in rocks ranging in age from pre-Cambrian to late Pennsylvanian.

Hugoton Embayment. All western Kansas commonly is included, as a petroliferous province, in the Hugoton Embayment. The southern part of the area was originally called Dodge City Basin and is regarded as the northern part of the great Anadarko Basin. Recent oil discoveries in the area, in lower and middle Pennsylvanian rocks, promise that southwest Kansas will take on greater importance as an oil-producing province. Of course, the Hugoton gas area is known throughout the industry.

After the Nemaha and Central Kansas structures were deeply truncated and pre-Cambrian rocks eroded from them for the last time, accumulation of sediments was taking place in all of Kansas. The areal geology represented in Figure 6 became buried under an unknown thickness of late Paleozoic (Pennsylvanian and Permian) rocks.

More recent movements also were effective. It is believed that even where there is no Mesozoic cover, Pennsylvanian and Permian beds were tilted and beveled to about their present extent before burial under Cretaceous or other Mesozoic sediments. This was at a time of rejuvenation of the Ozark Uplift and may have been at or near the close of Paleozoic time. While the sub-Cretaceous surface was undergoing erosion, the land surface in eastern Kansas sloped, together with the dipping rock layers, to the west into a Mesozoic basin.

Cretaceous sediments may have covered all of Kansas; post-Cretaceous erosion, it is believed, has uncovered the old surface in eastern Kansas, and has, of course, modified it. This sub-Mesozoic surface dates the Prairie Plains Monocline, the east Kansas structural province, so named because of the prevailing westward dip of Pennsylvanian and Permian outcropping rocks.

Nearly 3,000 feet of Cretaceous rocks and some 300 or 400 feet of older Mesozoic sediments remain in western Kansas. Since the end of deposition of Cretaceous sediments

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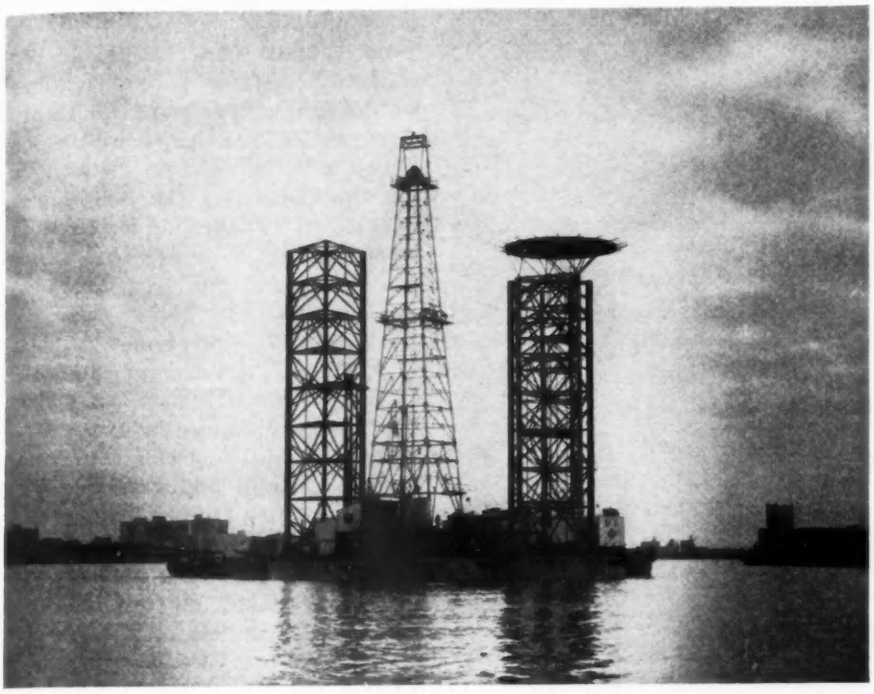

FIGURE 1—This is the Scorpion en route to Bahama California Company's Cay Sal Bank well off Florida.

At Cay Sal Bank

Drilling costs reduced with aerated seawater

By G. A. Krahn, E. B. Rubsamen, Jr. and S. J. Mathews, Jr., Engineers
Bahama California Oil Company, San Francisco

DURING THE PAST decades, great strides have been made in the development of the technology of rotary drilling fluids.

One of the latest developments has been the addition of compressed air to seawater, commonly known as aerated seawater, pioneered by Gulf Oil Corporation for use in drilling in areas of extreme lost circulation where abundant supply of seawater is available.

Conditions considered favorable for the application of aerated seawater are:

1. Abundant supply of seawater.
2. Formations to be drilled contain no shales or bentonitic sands. A well consolidated carbonate section is considered ideal.
3. Extreme lost circulation conditions anticipated.
4. No disposal problem of excess produced water.
5. No uncased up-hole horizons containing mobile hydrocarbons.

Limitations of aerated seawater:

1. Quality and quantity of ditch samples are reduced as compared with conventional mud systems.
2. Quality of electric logs is reduced.
3. Horizons having greater than normal formation pressures can not be drilled effectively with this method.
4. Hole size is significant in determining the amount of available air needed.
5. Regular bits should be used since jet bits usually require circulating pressures greater than normal air compressor design.
6. No apparent depths limitation provided compressor design capacity is sufficient to meet normal circulation pressures.

Gulf Oil Corporation, in a recent Florida Key well, experimented with aerated seawater and was sucessful after unsuccessful attempts at using conventional mud systems. The Bahama California Oil Company's Cay Sal Bank Well 1 was recently drilled from the surface to 15,138 feet using this technique which proved successful.

The Cay Sal Bank is located approximately 130 miles due south of Miami, Fla., and is essentially a platform of 1,750 square miles covered with depths of water ranging from 30 to 40 feet and surrounded on all sides by water depths up to 3,500 feet. The edges of the bank are composed of recent reefs which drop off abruptly. Cay Sal Bank Well 1 is located in the approximate center of this bank.

Prior to drilling the Cay Sal Bank Well 1, it was suspected that the regional geology of South Florida or North Cuba would be encountered. South Florida is well known for its zones of extreme lost circulation. In previous wells drilled in this area, both difficulty and expense were experienced in attempting to drill with conventional mud systems. Too, geologic control was difficult due to the absence of drill cuttings.

The formations encountered consisted of extremely porous limestone and dolomites with occasional caverns. Definite communication with the sea was established in that the annular returns were consistently greater than the seawater input and the static fluid level in the hole remained at sea level throughout.

Equipment for aerated saltwater includes:

1. Compressors—Four 7¾-inch and 5 by 6 two-stage water-cooled compressors capable of delivering a total of 1,800 cfm at 300 psi. Power was furnished by four 248 horsepower diesel engines.
2. Booster compressors—Two 4¾ x 11 single stage water-cooled compressors. They were capable of delivering a total of 1,800 cfm at 1,000 psi continuous and 1,500 psi intermittent. Two diesel engines rated

FIGURE 2—The Zapata Drilling Company's rig Scorpion is shown while drilling the recent Florida Keys Cay Sal Bank well.

at 412 horsepower furnished the power.

3. Valves and fittings—as necessary to inject air into outlet.
4. Air-water separator—30-inch O.D. by 15 feet with 6-inch air outlet.
5. Drill nipple deflector—Makeshift housing containing conventional drill pipe wiper.
6. Jet subs—Two custom made with two variable orifices per sub.

Application of aerated seawater on the Cay Sal Bank 1. The Cay Sal Bank 1 well was spudded March 23, 1958. A 36-inch hole was drilled 40 feet into the bank and 30-inch conductor caisson was cemented at a depth of 141 feet. A 26-inch hole was then drilled to 310 feet where complete returns were lost while drilling with straight seawater. Air was injected into the sea water and drilling progressed to 460 feet with only partial returns from the annulus. While drilling in this interval, air was observed to be coming up around the location as far out as 100 feet from the well bore. A hole was cut in the 30-inch conductor caisson 10 feet above sea level and drilling continued to 893 feet with full annular returns through this hole. Air, however, continued to boil up around the location. On this portion of the hole, an air output of 1,800 cfm and a pump output of 1,400 gpm at a pressure of 800 psi was used.

After cementing 20-inch casing at 834 feet, a 17½-inch hole was drilled to 4,000 feet. Aerated seawater used as the drilling fluid while drilling throughout this entire interval proved to be successful in cleaning the hole of drill cuttings and obtaining adequate formation samples. The proportion of air to seawater was varied between 2 to 4 standard cubic feet of air to one gallon of seawater while circulating at a rate of 900 and 400 gpm respectively. Circulating pressures remain fairly constant at 650 to 750 psi. Annular returns in the 17½-inch hole were in excess of the seawater input and were usually from 150 to 200 percent greater.

After cementing 13⅜-inch casing at 3,937 feet, a 12¼-inch hole was drilled to a depth of 9,947 feet again using aerated seawater as the drilling fluid. The proportion of air to seawater in this hole size fluctuated between 2 to 5 standard cubic feet of air to one gallon of seawater while circulating at a rate of 450 gallons per minute with 900 cubic feet per minute air, and 360 gallons per minute with 1,800 cubic feet per minute air respectively.

Circulating pressures varied between 600 to 900 psi while drilling in this interval. Annular returns were estimated to be 150 percent of the seawater input. While drilling at 5,400 feet, a jet sub with variable size orifices was added to the drill string in an attempt to reduce the period of no annular returns following trips and connections by reducing the hydrostatic head in the upper portion of the hole. The period of no circulation following trips was immediately reduced from one hour to less than 20 minutes and circulation was seldom lost during connections. As drilling progressed, a second jet sub was found to be necessary and was added to the string. See Table 1 for tabulation representing the actual hydraulics employed in drilling the 12¼-inch hole.

An 8½-inch hole was drilled to a depth of 15,138 feet using aerated seawater as the circulating medium after

cementing 9⅝-inch casing at 8,012 feet. The proportion of air to seawater in this hole size fluctuated from 5 to 6 standard cubic feet of air to one gallon seawater while circulating at a rate of 360 and 300 gpm respectively. Pressures varied between 900 to 1,100 psi. Annular returns throughout this interval were estimated to be 125 percent of the seawater input. See Table 2 for tabulation representing the actual hydraulic employed in drilling the 8½-inch hole.

After cementing 7-inch casing at a depth of 15,138 feet, a 5⅞-inch hole was drilled using a conventional mud system to a total depth of 18,906 feet.

Operating problems encountered using aerated seawater. These included:

1. Dilution caused by invading seawater from porous formations, which made it difficult to maintain a high pH factor in the injection water. This pH factor was maintained by the addition of hydrated lime to the injection water.
2. The absence of a filter cake and the lubricating qualities of mud, which seemed to make it difficult to get casing to bottom, particularly in the larger hole sizes.
3. In highly porous sections, it was difficult to obtain adequate formation samples without coring.
4. High cost of maintaining air compressor installation with drilling crews.
5. Annular returns tend to exceed 100 percent while drilling.

FIGURE 3—The distance between the Scorpion and shore installations required use of this type of helicopter.

Operating costs using aerated seawater. The over-all daily cost of drilling with aerated seawater for approximately nine months was $510 per day. This figure includes $67,815 for compressor rentals, $29,400 for parts and serviceman, $11,260 for diesel purchases and $18,810 for hydrated lime purchases.

Technical developments needed to improve aerated seawater as a drilling fluid.

1. Less expensive method of corrosion control.
2. An effective method of controlling the amount of air input so as to maintain returns as near to 100 percent as possible.
3. More rugged air compressor equipment designed for easier repair in the field.
4. Jet subs employing a differential pressure actuating device which would permit the orifice to open only when needed.

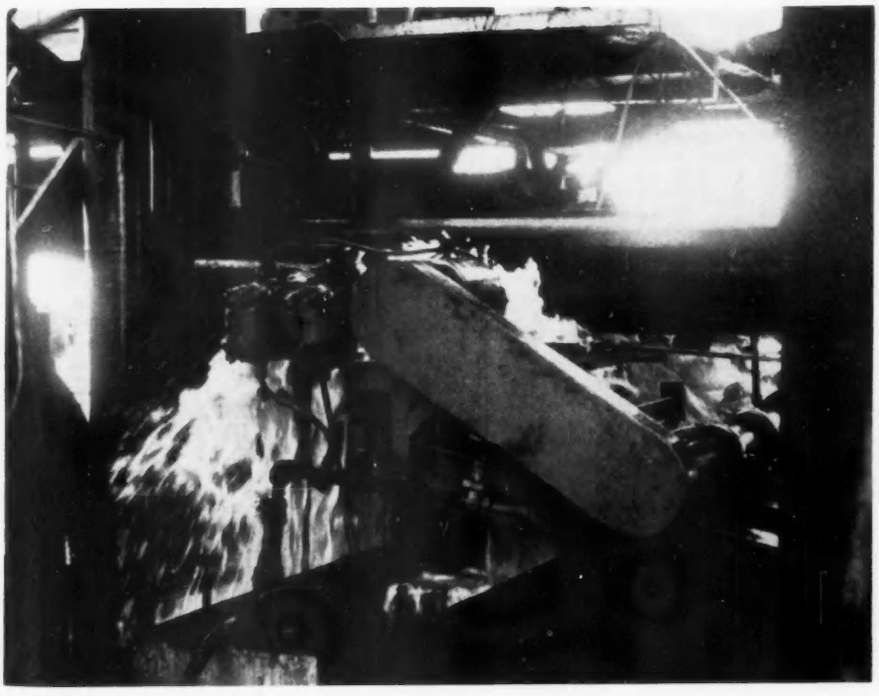

FIGURE 4—While drilling with aerated seawater, a jetting action developed in the annulus causing the circulating seawater to be jetted out of the hole. This resulted in an overflowing condition at the flow nipple as shown above.

Summary. A compressor installation designed to deliver 1,800 cfm at 1,000 psi continuous or 1,500 psi intermittent proved highly adequate in drilling the Cay Sal Well 1 to 15,138 fee. Ditch samples proved to be poor to fair while drilling with aerated seawater. When penetrating cavernous sections, samples stopped altogether or were reduced to flour-like consistency. Little difficulty was experienced in keeping the hole clean and free of drill cuttings while making trips for a new bit. Some difficulty with fill-up was experienced when running casing but this is believed to have been caused by the casing knocking off pieces of formation.

The proportion of air to seawater ranged from 2 to 6 standard cubic feet of air per gallon of seawater injected. Although dilution made it ex-

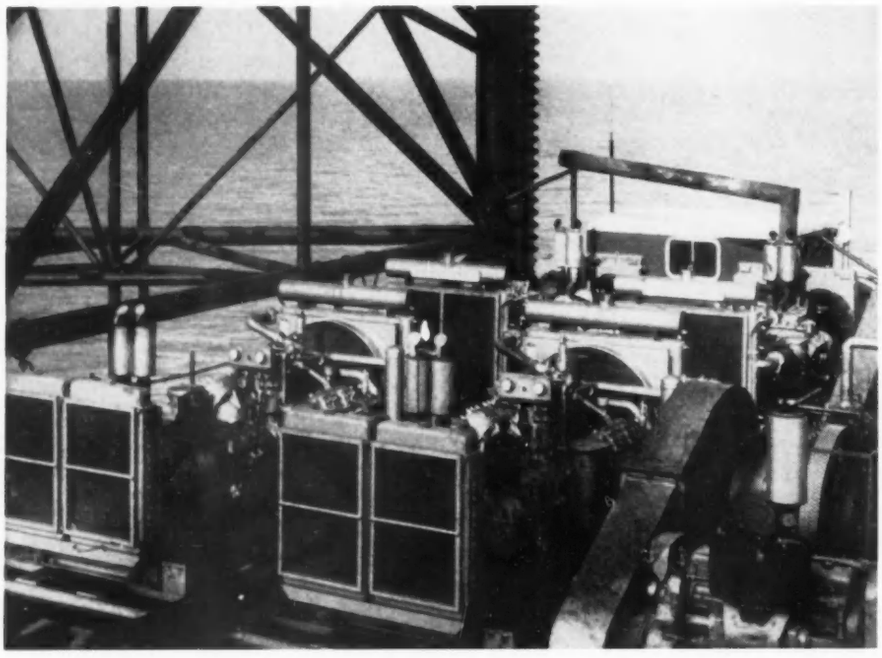

FIGURE 5—Four compressors rated at 1,800 cfm at 300 psi and two booster compressors rated at 1,800 cfm at 1,000 psi were used while drilling with aerated seawater on Bahama California Company's Cal Sal Bank well.

TABLE 1—These Are the Hydraulic Calculations While Drilling the 12¼-Inch Hole to 9,947 Feet.

DEPTH (Feet)	Air (CFM)	Seawater (GPM)	Pressure (PSI)	TOP JET		BOTTOM JET	
				Depth (Feet)	Orifice (Inches)	Depth (Feet)	Orifice (Inches)
5400	1800	450	900	1400	$2^{10}/_{64}$	.....	.....
	900	450	600	1400	$2^{10}/_{64}$	.....	.....
6500	1800	430	900	1400	$2^{10}/_{64}$	.....	.....
8600	1800	360	650	3000	$2^{12}/_{64}$	6000	$2^{14}/_{64}$
9947	1800	360	900	3000	$2^{12}/_{64}$	6500	$2^{14}/_{64}$

TABLE 2—Hydraulic calculations after setting 9⅝-inch casing and drilling ahead with 8½-inch hole.

DEPTH (Feet)	Air (CFM)	Seawater (GPM)	Pressure (PSI)	TOP JET		BOTTOM JET	
				Depth (Feet)	Orifice (Inches)	Depth (Feet)	Orifice (Inches)
11,000	1800	360	900	3500	$2^{12}/_{64}$	7000	$2^{14}/_{64}$
12,500	1800	340	1000	3500	$2^{12}/_{64}$	7000	$2^{14}/_{64}$
15,138	1800	300	1100	3500	$2^{12}/_{64}$	7000	$2^{14}/_{64}$

pensive, the hydrated lime treatment of seawater effectively prevented corrosion of the drill string. This was evidenced by tubular inspection of the drill string prior to and after drilling with aerated seawater.

Regular rock bits were run to decrease the necessary air injection pressures. Drilling crews proved unsatisfactory in properly maintaining and repairing the air compressors due to the complex nature of the equipment. It was found that a manufacturer's representative on the rig at all times was the best solution to this problem.

Jet subs were installed and run in the drill string below 5,000 feet to decrease the amount of time necessary to establish circulation after going in the hole with a new bit. As the hole was deepened, the jet subs were positioned in the drill string at about 3,500 and 7,000 feet. In all probability, it would be advantageous to employ jet subs above 5,000 feet.

The drilling crews experienced no difficulty in adapting to the technique of aerated seawater drilling.

Perhaps the most significant feature in drilling with any type aerated fluid is that in some instances, it may permit drilling in areas that otherwise could not be drilled.

While it is believed that the technique of drilling with aerated seawater has been successful in the Cay Sal well to a depth of 15,138 feet, it must be pointed out that the technique still is in its infancy and that through experience certain refinements will be made that will permit greater application to the drilling industry. —**The End**

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For Your PRODUCTION File

Here's how to improve your gas lift installations

PART 6: The Use of Gas Lift Valve Specifications and Force Balance Equations

By H. W. Winkler, Engineer
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VALVE SPECIFICATIONS and force balance equations play an important role in solving the numerous problems encountered in engineering gas lift installations. This article includes five important calculations utilizing this type information:

1. Determination of operating valve from surface closing pressure.

2. Calculation of approximate per cent fall-back in intermittent gas lift installation using surface casing pressure.

3. Design of intermittent gas lift installation based on surface closing pressure of valves.

4. Determination of opening pressures of unloading valves in a continuous flow installation.

5. Determination of re-opening pressure of valve or valves above operating valve in a continuous flow installation.

Designers of gas lift installations should always remember that simplified charts and equations do not provide the most efficient installation possible. Calculations presented herein for determining the operating valve, for estimating fall-back and for detailed designing of gas lift installations require one or more of the force balance equations for pressure operated valves derived in Figure 11.

The pressure operated gas lift valve functions in the same manner as a pressure regulator. That is, the basic operating principle is the same for both. The closing force for most valves is obtained by a pressure charged bellows, a spring, or a combination of pressure charged bellows and spring. These valves can be set to open on the surface at a desired pressure prior to installation in a well.

The opening and closing pressures of most pressure operated valves are not equal (unless the tubing pressure equals the closing pressure) because of the difference in areas over which these opening and closing pressures operate. When a pressure operated flow valve is closed, the gas pressure in the casing is exerted over the effective area of the bellows less the area of the port ($A_b - A_v$). After the valve has opened, the gas pressure in the casing acts on the total effective area of the bellows (A_b). Since the opening pressure is acting over a smaller area than the closing pressure and the closing force of a valve is constant, the opening pressure is higher than the closing pressure. Opening and closing pressure equations are shown in Figure 11. The difference between the opening and closing pressure of a valve is called spread.

In a well, tubing pressure (P_t) is exerted over the area of the port (A_v). This additional opening force reduces the opening pressure (O.P.) of the valve. The difference between the opening pressure (P_{vo}) of a valve without tubing pressure and the opening pressure (O.P.) of the same valve with tubing pressure exerted over the port area is called tubing effect (T.E.).

The tubing effect can be calculated by multiplying the tubing pressure at valve depth by the tubing effect factor (T.E.F.) for the valve. The larger the port size, the larger the tubing effect factor and the greater the tubing effect will be for a valve with the same size bellows. Tubing effect reduces the valve opening pressure (O.P.) and the spread. If the tubing pressure and

VALVE CLOSED–READY TO OPEN (In tester where $P_t = 0$)

VALVE WITHOUT SPRING

Opening Force = Closing Force

$$P_{vo}(A_b - A_v) = P_b(A_b)$$

$$P_{vo} = \frac{P_b}{(1 - A_v / A_b)}$$

In terms of P_b:

$$P_b = P_{vo}(1 - A_v / A_b)$$

VALVE WITH SPRING

Opening Force = Closing Force

$$P_{vo}(A_b - A_v) = P_b(A_b) + S_t(A_b - A_v) \qquad \textit{Equations 12}$$

$$P_{vo} = \frac{P_b}{(1 - A_v / A_b)} + S_t \qquad \textit{Equations 13}$$

In terms of P_b:

$$P_b = P_{vo}(1 - A_v / A_b) - S_t(1 - A_v / A_b) \qquad \textit{Equations 14}$$

or

$$P_b = (P_{vo} - S_t)(1 - A_v / A_b) \qquad \textit{Equation 14–A}$$

VALVE CLOSED–READY TO OPEN (In well with tubing effect)

Opening Force = Closing Force

$$O.P.(A_b - A_v) + P_t(A_v) = P_b(A_b)$$

$$O.P. = \frac{P_b}{(1 - A_v / A_b)} - P_t\left[\frac{A_v / A_b}{(1 - A_v / A_b)}\right]$$

$$O.P. = P_{vo} - P_t\,(T.E.F.)$$

$$O.P. = P_{vo} - T.E.$$

In terms of P_b from Equation 15:

$$P_b = O.P.(1 - A_v / A_b) + P_t(A_v / A_b)$$

Opening Force = Closing Force

$$O.P.(A_b - A_v) + P_t(A_v) = P_b(A_b) + S_t(A_b - A_v) \qquad \textit{Equations 15}$$

$$O.P. = \frac{P_b}{(1 - A_v / A_b)} + S_t - P_t\left[\frac{A_v / A_b}{(1 - A_v / A_b)}\right] \qquad \textit{Equations 16}$$

$$C.P. = P_{vo} - P_t\,(T.E.F.) \qquad \textit{Equations 17}$$

$$O.P. = P_{vo} - T.E. \qquad \textit{Equations 18}$$

In terms of P_b from Equation 15:

$$P_b = (O.P. - S_t)(1 - A_v / A_b) + P_t(A_v / A_b) \qquad \textit{Equations 19}$$

VALVE OPEN–READY TO CLOSE

Opening Force = Closing Force

$$P_{vc}(A_b) = P_b(A_b)$$

$$P_{vc} = P_b$$

Opening Force = Closing Force

$$P_{vc}(A_b) = P_b(A_b) + S_t(A_b - A_v) \qquad \textit{Equations 20}$$

$$P_{vc} = P_b + S_t(1 - A_v / A_b) \qquad \textit{Equations 21}$$

In terms of P_b:

$$P_b = P_{vc} - S_t(1 - A_v / A_b) \qquad \textit{Equation 22}$$

Substituting for P_b from Equation 14:

$$P_{vc} = P_{vo}(1 - A_v / A_b)$$

Substituting for P_b from Equation 14:

$$P_{vc} = P_{vo}(1 - A_v / A_b) \qquad \textit{Equations 23}$$

In terms of P_{vo}:

$$P_{vo} = \frac{P_{vc}}{(1 - A_v / A_b)}$$

In terms of P_{vo}:

$$P_{vo} = \frac{P_{vc}}{(1 - A_v / A_b)} \qquad \textit{Equations 24}$$

FIGURE 11: Force Balance Equations for Pressure Operated Nitrogen Charged Bellows Valves With or Without a Spring.

NOMENCLATURE

A_b—Effective area of bellows, sq. in.
A_v—Area of port with bevel, sq. in.
O.P.—Opening pressure of valve with tubing effect, psi
P_b—Nitrogen charge pressure inside bellows, psi
P_t—Tubing pressure at depth, psi
P_{vc}—Closing pressure of valve, psi
P_{vo}—Opening pressure of valve without tubing effect, psi
S_t—Spring pressure effect, psi
T.E.—Tubing effect, psi
T.E.F.—Tubing effect factor

closing pressure of a valve were equal, the opening pressure would be equal to the closing pressure and the spread would be zero.

The tubing effect factor (T.E.F.) of a valve is important. The fact that tubing effect reduces valve opening pressure can be used for selecting opening pressures (P_{vo}) of unloading valves. A minimum decrease in injection pressure is required for unloading if each succeedingly lower valve has a greater tubing effect factor (accomplished by increasing the port size for a given bellows size), or all of the unloading valves have a large tubing effect factor.

The tubing effect assures lifting from a lower uncovered gas lift valve although the valve above may have the same opening pressure (P_{vo}) with zero tubing pressure. The lower valve will have a greater pressure in the tubing at valve depth than the valve above due to the fluid column in the tubing.

A summary of force balance equations (Equations 12-24) for pressure operated nitrogen charged bellows valves, with or without a spring, is given in Figure 11. To use these equations, the gas lift valve manufacturer must supply the operator with the effective area of the bellows (A_b), the area of the port (A_v) and the spring pressure effect (S_t) if the valve has a spring. Usually, all valves in a well will be of the same type; therefore, the effecitve bellows area and spring pressure effect will be the same for every valve.

As an example; assume that each valve in a well had an effective bellows area of 0.70 square inches, a port area of 0.07 square inches and a spring pressure effect of 150 psi. The additional valve specifications required to use the force balance equations in Figure 11 then could be calculated as follows:

1. $A_v/A_b = \dfrac{0.07}{0.70} = 0.10$

2. $(1 - A_v/A_b) = 1 - 0.10 = 0.90$

3. $\text{T.E.F.} = \dfrac{A_v/A_b}{(1 - A_v/A_b)} = \dfrac{0.10}{0.90} = 0.11$

The spring pressure effect can be defined as the additional pressure required to open the valve due to the force exerted by the spring. The reason that the spring pressure effect must be considered apart from the bellows charge pressure is that the spring is not affected by well temperature.

The opening pressure of a nitrogen charged bellows valve in a tester on the surface, and the opening pressure of the same valve in a well differ due to well temperature and tubing effect. Before the opening or closing pressure of a valve in a well can be calculated, the temperature at valve depth (T_v) must be known. Generally, the temperature at the depth of each valve can be estimated with reasonable accuracy if the surface and bottom hole temperatures are known.

Most gas lift equipment manufacturers set the opening pressures (P_{vo}) of pressure operated nitrogen charged bellows valves in a tester with the valve at a temperature of 60° F. Thus, the opening pressure stamped on the valve is a function of the nitrogen charge pressure inside the bellows at a temperature of 60° F. Nitrogen is used in the bellows because it is noncorrosive, non-inflammable, readily available, inexpensive and most important—its deviation at elevated temperatures and pressures is known. Therefore, the nitrogen charge pressure inside the bellows at well temperature can be calculated accurately.

If nitrogen pressure versus temperature curves are not available, the following approximate temperature correction factor can be used to calculate the nitrogen charge pressure inside a bellows at well temperature:

$$F_{temp.} = [1 + 0.00215 \text{ per } ^\circ\text{F above } 60^\circ \text{ F}] \quad (25)$$

Therefore, to calculate P_b above 60° F:

$$P_b \text{ @ } T_v = (P_b \text{ @ } 60^\circ \text{ F})\ (F_{temp.}) \quad (26)$$

And to find P_b @ 60° F if P_b @ T_v is known:

$$P_b \text{ @ } 60^\circ \text{ F} = \frac{P_b \text{ @ } T_v}{F_{temp.}} \quad (27)$$

The deviation of nitrogen was considered in the derivation of the temperature factor ($F_{temp.}$).

The following five problem examples illustrate several important gas lift operation and design calculations which require valve specifications and force balance equations. All wells in the examples are assumed to be in the Texas-Louisiana Gulf Coast area (gas gravity = 0.6, gas surface temp. = 100° F, temp. @ depth = 70° F + 16° per 1,000 ft.) where the gas pressure at depth (P_v) for a given surface injection gas pressure (P_w) can be calculated as follows when no gas pressure at depth curves are available:

$$P_v = P_w + 2.2 \text{ psi/100 psi of } P_w/1{,}000 \text{ ft. of depth} \quad (28)$$

The same type of gas lift valve was used in all examples. Specifications necessary for calculating these problems with the exception of the bottom valve in Problem Example 3 are as follows:

1. $A_v/A_b = 0.112$
2. $(1 - A_v/A_b) = 0.888$
3. T.E.F. = 0.126
4. $S_t = 75$ psi

In Problem Example 3, the same type of valve with a larger port size was selected as the operating valve at 8,200 feet. This valve has an A_v/A_b ratio of 0.160, $(1 - A_v/A_b)$ factor of 0.840 and T.E.F. of 0.190. The spring pressure effect (S_t) is 75 psi. The upper valves in Problem Example 3 have the same port size and specifications as the valves in the other examples.

PROBLEM EXAMPLE 1

Determination of operating valve from surface closing pressure. One of the most widely used applications of valve specifications and force balance equations is the determination of the operating gas lift valve in an intermittent installation. In most intermittent gas lift wells the pressure in the tubing at the depth of the operating valve is approximately equal to the casing pressure at the instant the valve closes. Since the casing and tubing pressure at valve depth are approximately equal when the operating valve closes, the actual closing pressure of the valve will equal or nearly equal the calculated closing pressure.

The two-pen pressure recorder chart in Figure 9

(World Oil, Page 110, December 1959) was obtained from an intermittent gas lift well for which the following surface closing pressure analysis was calculated:

P_{vo} @ 60° F (psig)	L (ft.)	T_v @ L (°F.)	P_b @ 60° F (psig)	P_b @ T_v (psig)	P_{vc} @ L (psig)	P_{vc} @ Surf. (psig)
600	3,325	130	466	536	603	562
570	4,070	139	440	515	582	534
540	4,685	146	413	489	556	504
490	5,000	150	368	439	506	456

Where:

P_{vo} @ 60° F = Opening pressure of valve in tester, at 60° F, psig

L = Depth of valve, feet

T_v @ L = Temperature at depth L, °F

P_b @ 60° F = Nitrogen charge pressure inside bellows at 60° F psig

P_b @ T_v = Nitrogen charge pressure at T_v inside bellows, psig

P_{vc} @ L = Closing pressure of valve at depth L, psig

P_{vc} @ Surf. = Closing pressure of valve at surface, psig

The following calculations for determining the surface closing pressure of the bottom valve illustrate the procedure required to obtain the preceding tabulation:

1. Calculate nitrogen charge pressure at 60° F (P_b @ 60° F) using Equation 14-A:

$$P_b \text{ @ } 60° \text{ F} = (P_{vo} - S_t)\ (1 - A_v/A_b)$$
$$= (490 - 75)\ 0.888 = 368 \text{ psig at } 60° \text{ F}$$

2. Calculate nitrogen charge pressure at well temperature (P_b @ T_v) using Equation 26:

$$P_b \text{ @ } T_v = (P_b \text{ @ } 60° \text{ F})\ (F_{temp.})$$
$$= 368\ [1 + 0.00215\ (150 - 60)]$$
$$= 368\ (1.194) = 439 \text{ psig at } 150° \text{ F}$$

3. Calculate valve closing pressure at depth (P_{vc} @ L) using Equation 21:

$$P_{vc} \text{ @ } L = (P_b \text{ @ } T_v) + S_t\ (1 - A_v/A_b)$$
$$= 439 + 75\ (0.888)$$
$$= 506 \text{ psig at } 5{,}000 \text{ ft.}$$

4. Determine valve closing pressure at surface (P_{vc} @ Surf.) from gas pressure at depth curves:

P_{vc} @ Surf. = 456 psig at surface

The surface closing pressure of the operating valve was approximately 460 psig from the two-pen pressure recorder chart in Figure 9 (World Oil, page 110, December 1959.) Therefore, based on the above calculations, the operating valve is the bottom valve at 5,000 feet. The bottom valve was actually known to be the operating valve in this well from a bottom hole pressure survey.

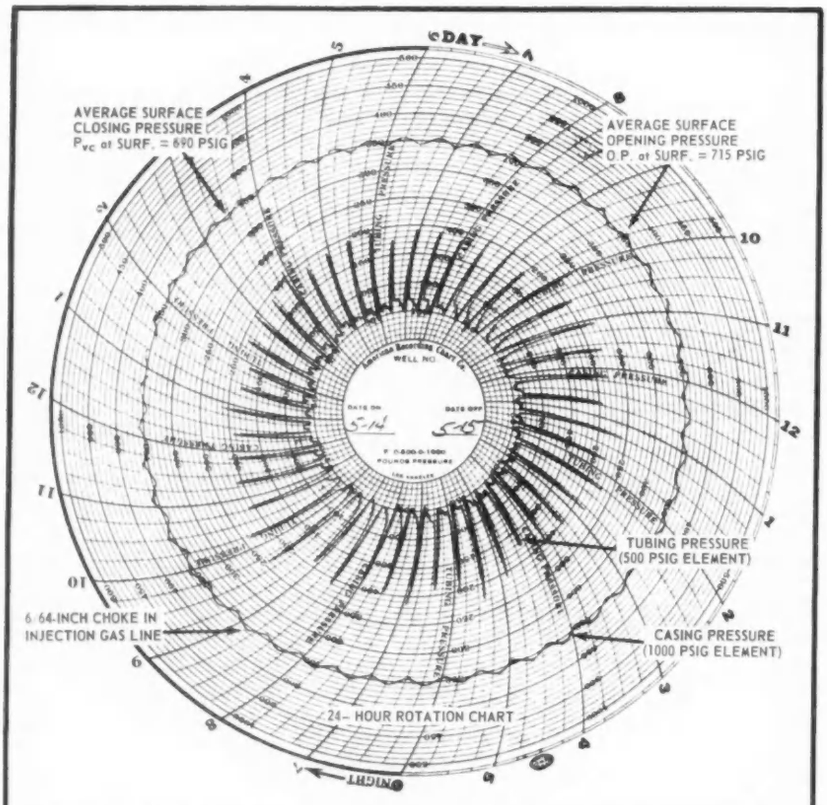

DAY
AVERAGE SURFACE CLOSING PRESSURE Pvc at SURF. = 690 PSIG
AVERAGE SURFACE OPENING PRESSURE O.P. at SURF. = 715 PSIG
TUBING PRESSURE (500 PSIG ELEMENT)
CASING PRESSURE (1000 PSIG ELEMENT)
6-64-INCH CHOKE IN INJECTION GAS LINE
24-HOUR ROTATION CHART
TUBING

FIGURE 12: Two-Pen Pressure Recorder from Intermittent Installation Without Surface Controller, Injection Gas Entering Casing Continuously Through Small Choke.

PROBLEM EXAMPLE 2

Calculation of approximate fall-back in intermittent gas lift installation using surface casing pressure. The two-pen pressure recorder chart in Figure 12 was obtained from an intermittent installation operating without a time cycle surface controller. Injection gas was entering the casing continuously through a 6/64-inch choke in the injection gas line. The opening pressure of the operating valve can be observed from the surface pressure in Figure 12.

If the opening pressure in a well (O.P. @ L) and the opening pressure at 60° F (P_{vo} @ 60° F) in a tester are known for the same valve, the tubing effect can be calculated. Since tubing effect is a function of liquid column height above the valve, the approximate starting slug volume and percent fall-back can be calculated for a given producing rate.

The first step would be to establish the operating valve by a surface closing pressure analysis as outlined in the previous problem example. The well is producing approixmately 140 bfpd through 2-inch tubing.

P_{vo} @ 60° F (psig)	L (ft.)	T_v @ L (°F.)	P_b @ 60° F (psig)	P_b @ T_v (psig)	P_{vc} @ L (psig)	P_{vc} @ Surf. (psig)
800	1,767	121	644	728	795	765
775	3,219	139	621	727	794	741
750	4,394	153	599	719	786	717
725	5,386	165	577	707	774	692
700	6,223	176	555	693	760	668
675	6,938	184	533	675	742	644
650	7,438	190	510	652	719	618
600	7,907	196	466	602	669	570

The 725 psig valve at 5,386 feet is the operating valve in this well based on the above calculations and the two-pen pressure recorder chart in Figure 12. After the operating valve has been determined, the approximate percent fall-back can be calculated as follows:

1. Determine opening and closing pressures at surface from two-pen pressure recorder chart in Figure 12:

   O.P. @ Surf. = 715 psig at surface

   P_{vc} @ Surf. = 690 psig at surface

2. Determine opening and closing pressure at depth (O.P. @ L, P_{vc} @ L) of operating valve from gas pressure at depth curves or calculate using Equation 28:

   O.P. @ L = 800 psig at 5,386 ft.

   P_{vc} @ L = 772 psig at 5,386 ft.

3. Calculate opening pressure at depth (P_{vo} @ L) of operating valve without tubing effect using Equation 24:

$$P_{vo} @ L = \frac{P_{vc} @ L}{(1 - A_v/A_b)} = \frac{772}{0.888} = 870 \text{ psig at 5,386 ft.}$$

4. Calculate tubing effect (T.E.) due to separator pressure and liquid column above operating valve at instant valve opens using Equation 18:

   T.E. = (P_{vo} @ L) — (O.P. @ L) = 870 — 800 = 70 psi

5. Calculate pressure in tubing at depth of operating valve (P_t @ L) at instant valve opens using tubing effect term in Equation 17:

   T.E. @ L = (P_t @ L) (T.E.F.)

$$P_t @ L = \frac{\text{T.E. @ L}}{\text{T.E.F.}} = \frac{70}{0.126} = 555 \text{ psig at 5,386 ft.}$$

6. Calculate starting slug volume above operating valve at instant valve opens (disregard slight increase in wellhead tubing pressure from surface to top of slug):

$$\text{Starting Slug Length} = \frac{(P_t @ L) - P_{sw}}{SFG} = \frac{555 - 60}{0.45} = 1{,}100 \text{ ft.}$$

   Starting Slug Volume = 1,100 ft. (0.00387 bbl./ft.) = 4.26 bbls.

   Where:

   P_{sw} = Surface wellhead tubing pressure = 60 psig from Figure 12

   SFG = Static fluid gradient = 0.45 psi/ft.

   Capacity of 2-inch tubing = 0.00387 bbl./ft.

7. Calculate percent slug fall-back:

$$\text{Production per cycle} = \frac{140 \text{ BFPD}}{46 \text{ cycles/day}} = 3.04 \text{ bbls./cycle}$$

$$\text{Percent Fall-back} = \left[\frac{4.26 - 3.04}{4.26}\right] 100 = 28.6 \text{ percent}$$

PROBLEM EXAMPLE 3

Design of intermittent gas lift installation based on surface closing pressure of valves. A simplified chart for determining valve depths was presented in Part 3 of this series (WORLD OIL, Page 160, October 1959). In this article it was pointed out that detailed valve spacing calculations are recommended for many installations. Valve depths with the exception of the top valve can be calculated based on a decreasing surface closing pressure with each succeedingly lower valve. The surface closing pressure of the top valve is based on the injection gas line pressure available at the well. The closing pressure at depth (P_{vc} @ L) of the valve above is used for calculating the depth of the next lower valve. If closing pressures at depth are used, Equation 4 in Part 3 becomes:

$$DBV = \frac{(P_{vc} @ L) - P_{sw} - FG\ (DVA)}{SFG} \qquad (29)$$

Where:

P_{sw} = Surface wellhead tubing pressure, psig

P_{vc} @ L = Closing pressure at depth of valve above, psig

DBV, DVA, FG and SFG were defined previously under Equations 3, 4 and 5 on Page 159 of Part 3.

If the well is loaded before pulling tubing and must be unloaded into the separator, Equation 3 in Part 3 also must be changed as follows:

$$\text{Depth of Top Valve, } L_1 = \frac{\text{Surf. K.O. Press.} - P_{sw}}{SFG} \qquad (30)$$

After valve depths have been calculated for the surface closing pressures assumed, the valve opening pressures at 60° F (P_{vo} @ 60° F) in a tester must be calculated before these valves can be ordered from the manufacturer. Data used for these calculations are similar to that for Problem Example 1 in Part 3 (WORLD OIL, Page 161, October, 1959). Use of the same data makes possible a comparison between the detailed design and the design obtained from the Simplified Valve Spacing Chart in Figure 6 of Part 3.

Valve depths used in the following valve opening pressure analysis were calculated based on the closing pressure at depth of the valve above and the following well data:

1. Surf. K.O. Press. = Oper. Press. = 800 psig
2. Daily Producing Rate = 40 bopd
3. Static Fluid gradient, SFG = 0.4 psi/ft.
4. Assumed Flowing gradient, FG = 0.04 psi/ft.
5. Surface wellhead tubing presure, P_{sw} = 75 psig
6. Wellhead tubing temperature, T_w = 100° F
7. Bottom hole temperature, T_v = 200° F at 8,200 ft.
8. Depth of bottom valve, L_6 = 8,200 ft.

The valve opening pressures at 60° F in a tester to be ordered from the gas lift equipment manufacturer can be calculated as follows:

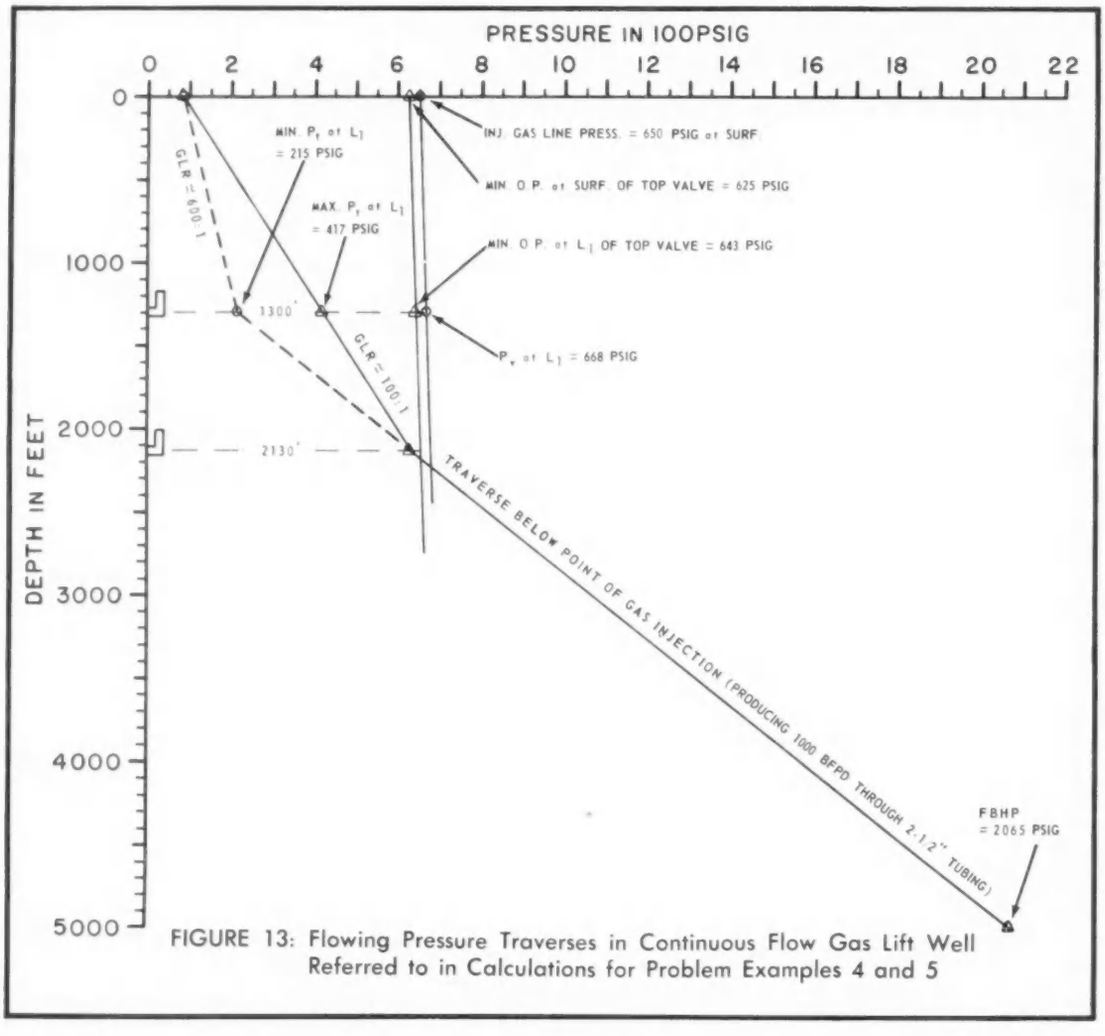


FIGURE 13: Flowing Pressure Traverses in Continuous Flow Gas Lift Well Referred to in Calculations for Problem Examples 4 and 5

P_{vc} @ Surf. (psig)	L (ft.)	T_v @ L °F	P_{vc} @ L (psig)	P_b @ T_v (psig)	P_b @ 60° F (psig)	P_{vo} @ 60° F (psig)	Order
750	1,810	122	780	713	630	785	785
740	3,395	141	795	728	620	774	775
730	4,865	159	808	741	611	764	765
720	6,215	176	819	752	603	755	755
690	7,455	191	803	736	575	723	725
650	8,200	200	767	704	540	719	720

Calculations required for the above tabulation will be illustrated using data for the bottom valve.

1. Determine closing pressure at depth (P_{vc} @ L) of valve for assumed valve surface closing pressure (P_{vc} @ Surf.) from gas pressure at depth curves, or calculate using Equation 28:

$$P_{vc} \text{ @ } L = 767 \text{ psig at } 8{,}200 \text{ ft.}$$

2. Calculate nitrogen charge pressure at operating temperature (P_b @ T_v) of valve using Equation 22:

$$P_b \text{ @ } T_v = (P_{vc} \text{ @ } L) - S_t\,(1 - A_v/A_b)$$
$$= 767 - 75\ (0.840) = 704 \text{ psig at } 200° \text{ F}$$

3. Calculate nitrogen charge pressure (P_b @ 60° F) of valve at 60° F using Equation 27:

$$P_b \text{ @ } 60° \text{ F} = \frac{P_b \text{ @ } T_v}{F_{temp.}} = \frac{704}{[1 + 0.00215\ (200 - 60)]}$$
$$= \frac{704}{1.301} = 541 \text{ psig at } 60° \text{ F}$$

4. Calculate valve opening pressure at 60° F (P_{vo} @ 60° F) in tester using Equation 13:

$$P_{vo} \text{ @ } 60° \text{ F} = \frac{P_b \text{ @ } 60° \text{ F}}{(1 - A_v/A_b)} + S_t$$
$$= \frac{541}{0.840} + 75 = 719 \text{ psig at } 60° \text{ F}$$

Operator should order 720 psig valve from gas lift equipment manufacturer.

In this example, all valves except the bottom valve have a $(1 - A_v/A_b)$ factor of 0.888. The bottom valve has a larger port size; therefore, the $(1 - A_v/A_b)$ factor is only 0.840. It is not uncommon to run a larger port size valve as the bottom one or two valves in a deep intermittent gas lift installation. The port size is not considered in the valve design determined using the Simplified Valve Spacing Chart in Figure 6 of Part 3 of this series.

If the 650 psig valve at 8,165 feet in Problem Example 1 for the Simplified Chart in Part 3 was an unbalanced valve with a large port, the surface closing pressure would be extremely low compared to the injection gas line pressure available for lifting the well. In other words, when a valve with a high (A_v/A_b) ratio is run below a valve with a lower (A_v/A_b) ratio, the opening

pressure at 60° F (P_{vo} @ 60° F) of the valve with the higher ratio does not have to be decreased appreciably, if at all, to result in a significant decrease in surface closing pressure when compared to the valve above.

PROBLEM EXAMPLE 4

Determination of opening pressures of unloading valves in a continuous flow installation. In design calculations for a continuous flow installation, the opening pressure (P_{vo} @ 60° F) in a tester at 60° F. of the unloading valve or valves should be calculated based on the minimum tubing pressure at valve depth (Min. P_t @ L) which is required to uncover and allow gas passage through the next lower valve. The nitrogen charge pressure at operating temperature (P_b @ T_v) for each valve should be calculated for the minimum tubing pressure which will occur during the unloading process. If the nitrogen charge pressure at operating temperature for a valve is known, the valve opening pressure at 60° F in a tester can be calculated.

The opening pressure at 60° F in a tester of the top valve will be calculated using data shown in Figure 13. The top valve is at a depth (L_1) of 1,300 feet where the temperature (T_v) is 116° F. For injection gas to enter the tubing through the second valve at a depth (L_2) of 2,130 feet with a desired differential across the second valve of approximately 50 psi, the pressure in the tubing at 1,300 feet must be decreased to 215 psig (Min. P_t @ L_1) by injecting a sufficient volume of gas through the top valve. The injection gas pressure at depth of the top valve (P_v @ L_1) is 668 psig and this pressure would represent the design opening pressure at depth (O.P. @ L_1) for the minimum tubing pressure of 215 psig at 1,300 feet.

In other words, the top valve must remain open with a tubing pressure as low as 215 psig at 1,300 feet in order to unload the well to the second valve. The opening pressure at 60° F. (P_{vo} @ 60° F) of the top valve can be calculated as follows:

1. Calculate nitrogen charge pressure at operating temperature (P_b @ T_v) of top valve using Equation 19:

$$P_b \text{ @ } T_v = [(P_v \text{ @ } L_1) - S_t] \ (1 - A_v/A_b) + \text{Min. } P_t \text{ @ } L_1 \ (A_v/A_b) = (668 - 75)\ 0.888 + 215\ (.112) = 551 \text{ psig at } 116° \text{ F}$$

2. Calculate nitrogen charge pressure at 60° F (P_b @ 60° F) of top valve using Equation 27:

$$P_b \text{ @ } 60° \text{ F} = \frac{P_b \text{ @ } T_v}{F_{temp.}} = \frac{551}{[1 + 0.00215\ (116 - 60)]}$$

$$= \frac{551}{1.120} = 492 \text{ psig @ } 60° \text{ F}$$

3. Calculate opening pressure at 60° F (P_{vo} @ 60° F) of top valve in tester using Equation 13:

$$P_{vo} \text{ @ } 60° \text{ F} = \frac{P_b \text{ @ } 60° \text{ F}}{(1 - A_v/A_b)} + S_t$$

$$= \frac{492}{0.888} + 75 = 554 + 75$$

$$= 629 \text{ psig at } 60° \text{ F}$$

Order 630 psig opening pressure valve from gas lift equipment manufacturer.

PROBLEM EXAMPLE 5

Determination of reopening pressure of valve or valves above operating valve in continuous flow installation. The reopening pressure analysis should be calculated before increasing the casing pressure of a continuous flow installation if the operating valve is not the top valve. The minimum opening pressure at the surface (Min. O.P. @ Surf.) of the upper valve or valves is calculated based on the maximum tubing pressure at valve depth (Max. P_t @ L) with the point of gas injection at the operating valve. This analysis is extremely useful for a continuous flow installation in which single point injection from the deepest valve possible is required due to limited injection gas volume. These calculations will be illustrated using Figure 13.

It is assumed that the operating valve is the second valve at 2,130 feet, and the maximum pressure in the tubing at the depth of the top valve (Max. P_t @ L_1 is 417 psig with the point of gas injection at 2,130 feet. The minimum opening pressure at the surface (Min. O.P. @ Surf.) of the top valve would be the maximum casing pressure possible without opening the top valve. In other words, the casing pressure should not be increased to the minimum opening pressure of the top valve if this valve is to remain closed.

Calculations for determining the reopening pressure of the top valve are as follows:

1. Calculate minimum opening pressure at depth (Min. O.P. @ L_1) of top valve using combination of Equations 16 and 17:

$$\text{Min. O.P. @ } L_1 = \frac{P_b \text{ @ } T_v}{(1 - A_v/A_b)} + S_t - (\text{Max. } P_t \text{ @ } L_1)\ (\text{T.E.F.})$$

$$= \frac{551}{0.888} + 75 - 417\ (0.126)$$

$$= 621 + 75 - 53 = 643 \text{ psig at } 1{,}300 \text{ ft.}$$

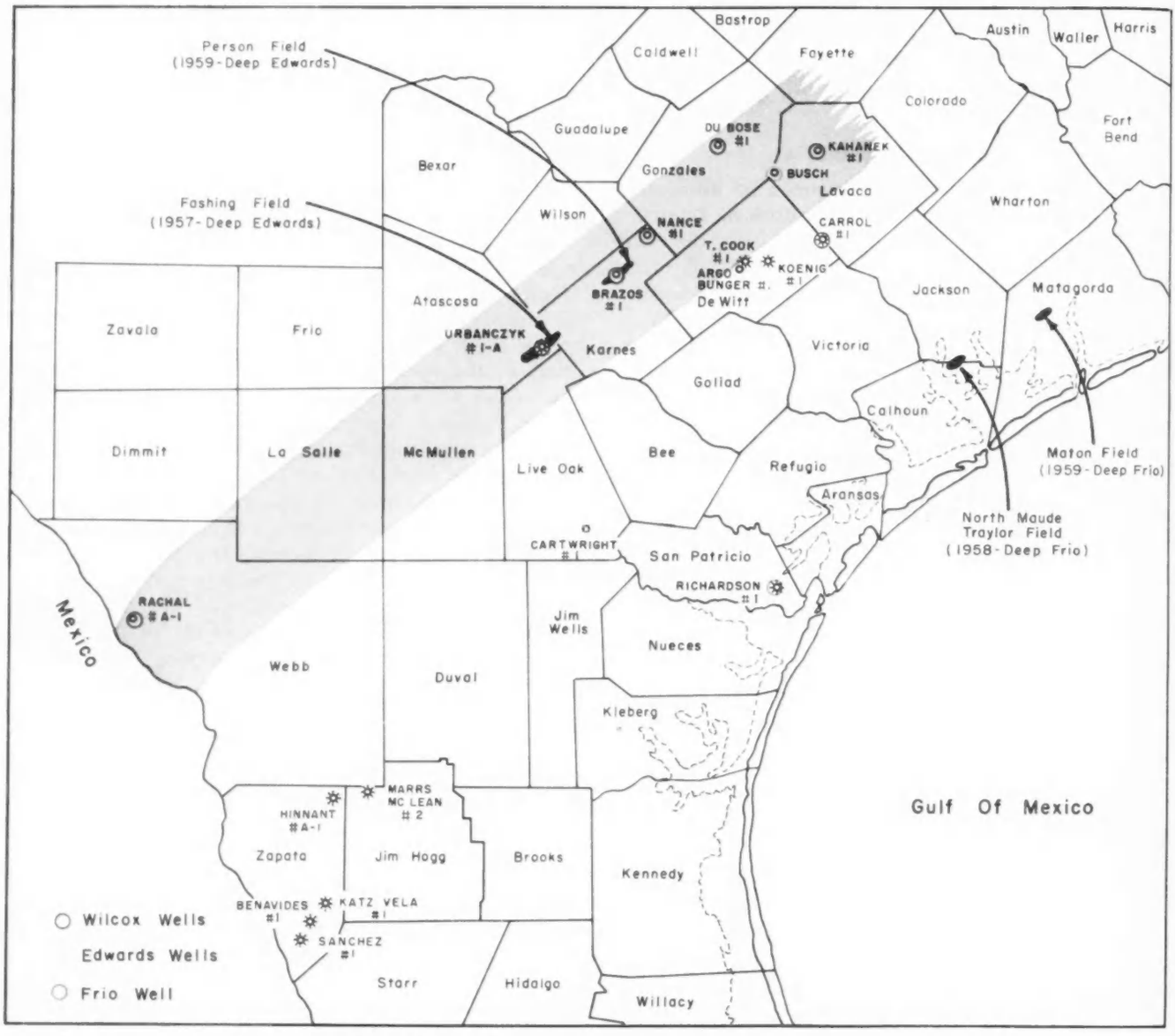
2. Determine minimum opening pressure at surface (Min. O.P. @ Surf.) of top valve from gas pressure at depth curves:

Min. O.P. @ Surf. = 625 psig at surface

If the casing pressure at the surface is increased to 625 psig or more, the top valve will open. The operator should keep the casing pressure at least 10 to 20 psi less than the minimum opening pressure of the upper valve or valves to assure that single point gas injection will continue from the operating valve.

For a producing rate of 1,000 bfpd through 2½-inch tubing in Problem Example 5, the gas-liquid ratio while injecting gas through the top valve would be over 600 cubic feet per barrel. The ratio would be less than 100 cubic feet per barrel for the same producing rate with the point of gas injection at the depth of the second valve. Thus, the daily injection gas requirement is six times greater while gas lifting from the top valve as compared to lifting from the second valve.

TO BE CONTINUED



Critical Wells in South Texas' Deep Edwards, Wilcox, Frio Trends

What's ahead for deep Edwards play?

A WORLD OIL survey of major operators in the area reveals:

- Deep Edwards wildcatting activity may hit new peak in 1960.
- If several critical wells now in various stages of drilling become good producers, look for exploratory activity to increase along the deep Edwards, Wilcox and new Frio trends from the Mexico border to Lavaca County

AFTER SIX YEARS of sporadic exploratory drilling, activity in South Texas' deep Edwards trend is expected to hit a new peak in 1960. However, much will depend on the following rank wildcats either planned or nearing completion below 10,000 feet in late December:

- **Moran and Mobil Oil's Kahanek 1** in Lavaca County. Since no previous deep test has reached the Edwards so far down dip (except in McMullen County), this well should provide a new and more complete evaluation of the trend.

Although little information was available in late December, reports were that 7-inch casing was being run—upwards of 300 feet of Edwards had been penetrated, with gas shows—heavy lease and royalty play is underway in the area.

- **Shell Oil Company's Wm. M. Carroll 1** in De Witt County. Also a tight well, it is reported to be a 20,000-foot test, projected to the Edwards. The well was below 18,500 feet in late December.

- **L. A. Nordan's Copano Rachal A-1** in Webb County. This 13,500 foot test was near 11,000 feet in late December, topping the Edwards at 8,750 feet. The well is expected to provide valuable information on most of the lower Cretaceous section.

Nordan has more than 110,000 acres under farmout agreement in the area, and is planning 10-15 deep Edwards tests in the next three years.

- **Ada Oil Company's location** in Karnes County along the Person field trend.

- **Cecil Hagen's Edwards test** planned for Gonzales County.

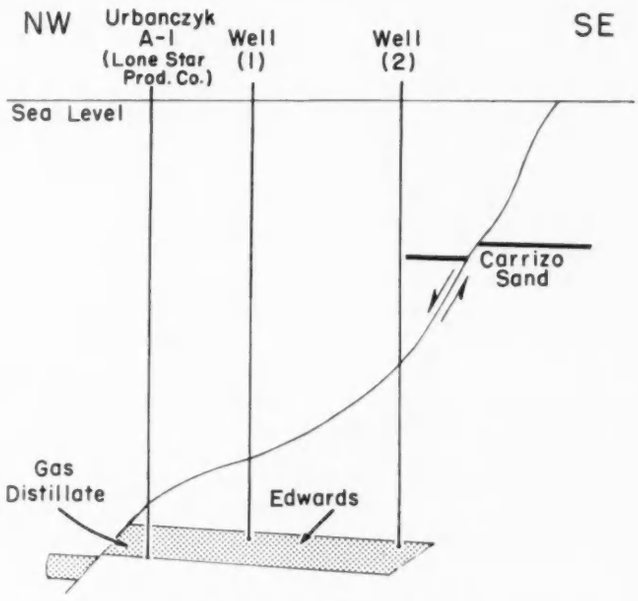
Should these wells prove to be good producers from one or more horizons, they will touch off a deep drilling play that may well reach from the Mexico border to areas northeast of Lavaca County. There also will be deep drilling activity on the edges of known shallower fields, particularly where up-to-the-coast faults are known in Lavaca, Fayette, Gonzales, Karnes, and De Witt counties.

To give an example of the increased deep Edwards play in recent months, only three rank wildcats were drilled along the trend during 1958. All were dry. During 1959, 13 deep Edwards wildcats were drilled including the Person field discovery well, one non-producer, Mobil's apparent Lavaca County discovery, and four Webb County wildcats still drilling in late December.

Predictions are that most of the deep Edwards prospects with any merit will be drilled in the near future.

Leasing activity is heavy throughout the trend. Gonzales, northern McMullen, La Salle, Karnes, and south Atascosa counties are nearly leased up. Lavaca and Webb counties are getting heavy lease and royalty play.

Two fields spark activity. The recent upsurge in deep Edwards wildcatting is a direct result of two major discoveries—the Fashing gas-condensate field in Atascosa and Karnes counties, discovered by Lone Star Producing Company in late 1956, and Karnes County's Person oil field, discovered by Brazos Oil and Gas Company last August.



Cross Section of Fashing Field

Since the deep Fashing field was discovered, 33 producing wells and 3 dry holes have been drilled. Of the producing wells, 24 are dual and 9 are single completions. In late December, five wells were drilling in the field, with no inactive locations.

Reserves are estimated at 500-750 billion cubic feet.

The Person field produced the first oil of any significance found in the Edwards below 10,000 feet, and is considered to be the most important Edwards oil discovery in 30 years.

In late December, three single producing wells had been completed, four wells were drilling and two were being completed. It is estimated that 25-30 wells will be completed in the field within the next 24 months.

An important factor in the future of the field may be a planned deep test to the Sligo (14,000-14,500 feet) by Brazos Oil and Gas early in 1960.

Following is a general description of the Fashing and Person fields:

FASHING FIELD

Geologic features. During their search for production in the Fashing area, Lone Star Producing Company geologists found a closure on a known up-to-the-southeast fault with a throw of about 300 feet at the Carrizo-Wilcox level (3,700 feet).

Establishment of Carrizo oil production proved the closure. Absence of Edwards production against the Edwards trace of the fault was inconsistent with other similar situations in the area.

In fact, conforming geological features in Atascosa County's Charlotte, Jourdanton, Imogene, Pleasanton, Muil, and Fashing fields led to the following general conclusion: If an accumulation of oil and/or gas is found in one bed on the upthrown side of an up-to-the-coast fault in the Fashing area, and if that fault is the dominant sealing factor, drilling usually reveals additional producing zones in the same fault block.

Although it is not new, this concept was responsible for the discovery of the Fashing Edwards field, and

Average Reservoir Data for Fashing (Edwards Lime) Field

	Zone A	Zone B	Field
1. Number of wells in which Edwards was wholly or partially cored	3	3	3
2. Total feet of Edwards Lime cored	573	760	1333
3. Total feet of core recovered	569	739	1308
4. Feet of core included in averages (each foot having 0.1 + md. was included)	377	294	671
5. Average porosity in percent	14.11	11.89	12.96
6. Average permeability in millidarcys	11.43	5.42	8.80
7. Average residual oil saturation (% pore space)	4.93	4.51	4.75
8. Average interstitial water saturation (% pore space)	29.54	25.00	27.55

probably will result in the discovery of many similar fields in the future.

With so few wells completed in such a large area, much remains to be learned of deep Edwards geology. Variable porosity zones at the top of the Edwards represent a crucial factor affecting production. Whether an unconformity and/or erosion surface exists at the top of the Edwards may be vital.

Reefing in the Edwards is suspected in McMullen and La Salle counties and possibly elsewhere. This is a subject of considerable controversy which is probably not yet resolved.

Salt domes near Tilden in McMullen and at Pescadito in Webb County pierce the entire Cretaceous section through to the Wilcox, and further complicate the picture. Widespread facies changes in the Cretaceous limestones, Edwards included, are bound to occur over so large an area.

Well data. Open flow gas potentials range from a high of 110 MMcf per day to a low of 2.65 MMcf per day.

Fashing field Edwards gas is sour, containing 6½ percent carbon dioxide and 2 percent sulfur. Wells yield an average of 16 barrels of condensate and ¾ ton of sulfur per MMcf.

The "A" or upper porosity zone occurs at 10,230-10,461 feet; the "B" or lower porosity zone at 10,511-10,921 feet. Each zone varies from 50 to 350 feet in thickness.

Though in separate reservoirs, the two zones have a common water level—minus 10,439 feet. Initial well pressures in both zones were approximately 5,125 psi.

Currently, the Fashing field is capable of producing 250 MMcf gas per day, or the capacity of the three desulfurization plants in the area.

Allowables are 2.23 billion cubic feet per month from the "A" zone and 2.09 billion cubic feet from the "B" zone. To date, 8,383 productive acres have been assigned to the "A" zone and 4,830 acres to the "B" zone. Four completed wells had not yet been filed for in late December.

United Gas Pipe Line Company is purchasing all of the field's production at an average price of 15½-16 cents per Mcf.

Operators in the field include Lone Star Producing Company, Gulf Oil Corporation, Carrl Oil Company, Phillips Petroleum Company, Gillring Oil Company, Renwar Oil Corporation, and Christi, Mitchell and Mitchell.

Typical completion program. Sonic and induction logs are run to determine lithology and porosity prior to

History of Significant Deep Edwards Discoveries

1953

Humble Oil & Refining Company completed an important deep Edwards gas well in McMullen County's shallow San Miguel field. The well had an open flow potential of 70 MMcf per day from Edwards porosity at 10,149-10,182 feet. Only two deep Cretaceous tests were drilling at the end of the year, one in La Salle County and one in Dimmitt County.

1954

The deep Cretaceous trend was extended southwest in 1954 with the completion of the Stanolind Martin 1, a gas discovery south of Artesia in La Salle County. Initial potential was 4.7 MMcf gas per day, open flow, from the deep Edwards, 10,092-10,120 feet.

1955

Three McMullen County deep Edwards gas-condensate discoveries were completed, ranging from 10,661 to 11,170 feet in depth.

1956

Amerada's Ethel Lowe Craig 1 (Lowe Ranch field) McMullen County, became the deepest Edwards production in the district, producing from open hole at 13,950-14,479 feet. Open flow potential was 97.5 MMcf gas per day.

Standard Oil of Texas' J. B. Henry 1 (Henry field) in McMullen County was completed at 10,549-11,060 feet, with an open flow potential of 40 MMcf gas and 18 barrels condensate per day.

Stanolind's La Salle County Cooke 1 (Cooke field) was completed at 10,815 feet, flowing 4.6 Mcf per day.

1957

Lone Star Producing Company's Urbanczyk 1A in southeastern Atascosa County spurred additional lease plays on the downdip Edwards trend. The well reached TD of 10,921 feet in 1956, but was officially completed for initial potential of 36 MMcf gas and 855 barrels condensate per day in January 1957. This was the deepest downdip Edwards production on an up-the-coast fault trap.

Humble Oil & Refining Company's J. C. Dilworth, Jr. 2 (Dilworth field) in McMullen County was completed with a potential open flow of 36.5 MMcf gas per day from 10,670-10,765 feet.

Jupiter Oil's South Texas Syndicate 2 (Mula field) was completed in McMullen County with open flow potential of 12.8 MMcf gas per day from 10,531-10,575 feet.

(For 1958-1959 information and expected activity in 1960, see story.)

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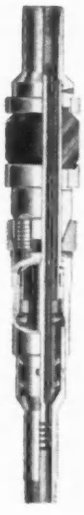

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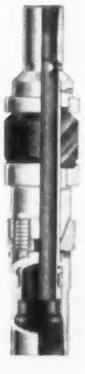

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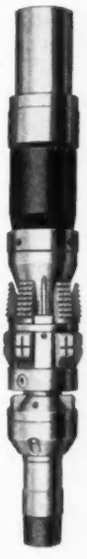

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running casing. Either 7-inch casing or 5½-inch casing is used, depending on whether the wells are to be dually completed.

About 375 sacks of cement are used to cement the bottom of the casing, and 500 sacks are run through the DV tool (located at 4,700 feet) and circulated to the surface. Fresh water must be protected down to this depth.

The wells usually are perforated at 50-foot intervals in both producing zones.

Two strings of tubing are used—a 2⅜-inch string with no collars and a 2⅜-inch EUE string. Two packers separate the producing zones.

There has been some acidizing; however, the general practice is to spot 500 gallons of mud acid to clean up the face of the well bore.

Average cost of a producing well: $175,000.

Drilling program. Drill 15-inch hole to 1,700 feet, set 10¾-inch casing. Drill 9⅞-inch hole to TD, set 7-inch casing for dual wells and 5½-inch for single wells.

From 10 to 15 drill collars are used, depending on the drilling contractor.

There is little blowout danger, and mud control is not critical. There is a change over from phosphate mud to low lime (10 percent oil emulsion) at 6,500 feet.

There is some lost circulation. Deviations have been experienced up to 5 degrees; however, normally straight hole conditions prevail.

Typical rotary speed is 50-125 rpm. Usual weight on bit: 20,000-60,000 pounds. Average completion time from spud into tanks: 55 days.

Equipment and conditions. Standard and jackknife 1,350 hp rigs are used. One mud pump and one standby, with pressure capacities of 1,100-2,500 are standard on most wells. The standby is used for mud mixing.

Three blowout preventers are used, and one vibrating screen shale shaker. Above ground pits are used, usually made of steel.

The prevailing footage rates are $3-$5; hourly rates, $25-$30.

Water supply is poor in the Fashing area, with surface and underground wells the primary source. Diesel and gas-propane fuels are available.

Living conditions for crews are poor. There is a housing shortage in Kenedy, about 20 miles south of the field and the next nearest housing is 50-60 miles away. Kenedy is the nearest supply center. Machine shop and service facilities are at Alice, Corpus Christi and Victoria.

PERSON FIELD

The field is an upside fault closure, believed to be typical of those which have produced other fields in the deep Edwards.

Each of the three wells in the field are producing the 225 barrels per day discovery allowable. Maximum allowable per well has not yet been determined.

The discovery well, Brazos Oil and Gas Company's Otha Person 1, was completed August 30, with an open flow potential of 650 barrels of 38.9 gravity crude oil per day through a 17/64-inch choke. The well had a flowing tubing pressure of 1,550 psi from deep Edwards perforations at 10,886-10,900 feet.

The three operators, Brazos Oil and Gas Company, Shell Oil Company and Argo Oil Corporation, have not yet had enough experience in Person to determine the limits, reserves, or typical drilling and completion programs.

Deep Drilling in Wilcox and Frio May Outpace the Lower Edwards Play

DEEP DRILLING in south Texas will by no means be restricted to the Edwards trend during 1960. In fact, some operators believe there will be even greater wildcatting activity in search of deep Wilcox and Frio pays.

Several critical wells were recently completed, some are now drilling and others are in the planning stage that will shed considerable light on the two trends.

Argo Oil's Thomas Cook 1 in southern De Witt County, Lone Star Producing's Koenig 1 six miles northeast of the Argo well and Shell Oil's apparent discovery, Wm. M. Carroll 1, located 15-20 miles southeast of the Lone Star Well are expected to increase lower Wilcox drilling in southern Lavaca, De Witt, Karnes, and Live Oak counties.

The Argo discovery was a gas-condensate well with a potential of 6 MMcf gas and 50 barrels condensate per day. Lone Star's Koenig 1 potentialed 33.5 MMcf gas and 60 barrels condensate per day from the lower Wilcox at 10,700-10,800 feet.

Other significant deep Wilcox tests are the Shell-Tidewater Holman 1 drilling below 13,000 feet in southeast Live Oak County in late December, and the Cecil Hagen test planned to penetrate the entire Wilcox section in western Lavaca County. Upper and lower Wilcox tests are being watched closely in Zapata and Jim Hogg counties.

Should the above wildcatting activity produce good discoveries, deep Wilcox activity is expected to increase from the Mexico border to Lavaca County.

Significance of the new deep Frio trend was established last year with the Tidewater Richardson 1 discovery in San Patricio County, which flowed 600 MMcf gas and 34,000 barrels of condensate in 12 months. Four similar producers have since been completed in the field. Initial pressures have held up well.

Experience to date indicates that south Texas' new deep Frio trend is one of the most promising deep areas in the U.S.

Two significant rank wildcats now are drilling in the Rio Grande Valley deep Frio area. They are:

Gulf Oil's Stone 1 drilling below 9,500 feet on a 12,500-foot permit in Willacy County just west of the Willamar oil field which has produced 15 million barrels of oil from the Marg. Frio.

Texaco's State Tract 1 drilling below 7,200 feet in Cameron County on a 13,400-foot permit a few miles north of Port Isabel, Texas.

The two counties in which these wells are being drilled have had poor to spotty production (mostly oil) to date and represent one of the few remaining areas in Texas in which appreciable quantities of acreage can be obtained.

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Offshore tanker island towed to Iraq

Looking like a Mississippi River steamer, this is part of a deep-water tanker terminal starting a 7,000-mile tow from England, where it was built, to the Persian Gulf, where it was scheduled to be erected 24 miles offshore from Iraq. When it arrived late in September, the rig was separated into two sections, each of which put down hydraulically operated legs for "walking" on the floor of the 80-foot deep Gulf.

The two mobile units were due to serve as working platforms to build the 1,200 foot long terminal for Basrah Petroleum Company of Iraq. When work is completed, both platforms will be incorporated into the terminal as permanent structures. One will become a heliport, and the other will support permanent living quarters. Two 32-inch submarine pipe lines will be built to link the terminal with Fao, the present oil port. The terminal will accommodate two 65,000-ton tankers simultaneously. In the photo, the forward section mounts a large crane for pile driving, and the stern section carries the 3-story air-conditioned permanent quarters. The rig is operated by a joint venture sponsored by Raymond International (U.K.), Ltd., a London-based subsidiary of Raymond International Inc., New York. The other two partners are Richard Costain Middle East, Ltd. and DeLong Overseas, Ltd.

Oil discovered in Gabon by Mobil and French firm

Two affiliates of Mobil International Oil Company jointly with Societe des Petroles de l'Afrique Equatoriale Francaise (SPAEF) have made an oil discovery in the Republic of Gabon, Africa.

The well, Rembo Kotto 1, produced 28 barrels of light gravity oil from a depth of about 2,000 feet during a two-hour drill-stem test. The indicated daily rate was 340 barrels.

The Republic of Gabon is located north of the Congo and south of the Cameroons on the west coast of Africa. The Mobil International affiliates participating in the well are Mobilrex and Mobil Exploration Equatorial Africa, Inc.

Under the terms of the agreement with SPAEF, the Mobil affiliates have a 50 percent interest in the well. A drilling program to evaluate the new field is planned. Rembo Kotto 1 was scheduled to be continued to test deeper formations.

The Mobil affiliates have programmed for expenditures of $45,000,000 (with a minimum of $22,500,000) during the six-year period under their agreement with SPAEF.

Mobil International Oil Company and Societe des Petroles de l'Afrique Equatoriale Francaise have made a new oil discovery in the Republic of Gabon, Africa. The discovery well, Rembo Kotto 1, was located at point indicated on map.

The agreement covers 6,175,000 acres in the Gabon and Congo republics.

Terms of the agreement between the companies have been approved in general by the Gabon government. Final approval will be sought at the next meeting of the legislative assembly. SPAEF is operator of the discovery well.

FIGURE 1—Equipment being loaded aboard a helicopter which will deliver units to offshore rig. Use is being made of baggage and passenger compartments.

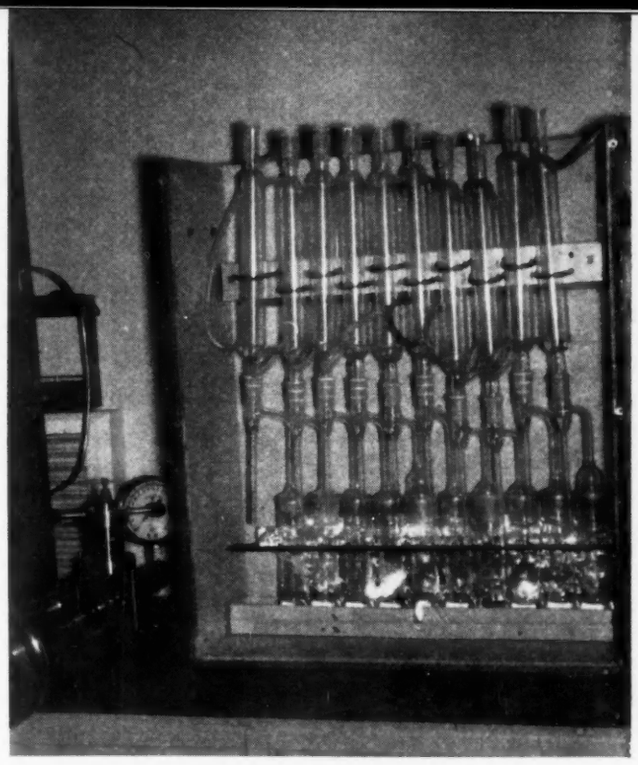

FIGURE 2—Compactness of the extraction equipment is shown in this photograph (right) of one of the 10-unit ASTM type extractors. Front and top of case have been removed.

Portable core analysis lab saves offshore rig time

FIGURE 3—Portability of mobile laboratory is demonstrated as engineer passes one of the suitcase size units to author aboard a barge at Santa Barbara preparatory to going to offshore platform.

Complete core analysis laboratory equipment, reduced to suitcase-size packages for easy transporting to offshore locations saves helicopter and additional personnel services

By Robert E. Lampkin
General Manager
Petroleum Technologists, Dallas

ANALYZING CORES on offshore wellsites is creating an increased amount of interest among the oil operators. After careful study of the problems and personnel requirements, in many instances the operators were able to reduce costs by having a service company laboratory perform the core analysis at the well location.

Recently, a specially designed, portable laboratory, equipped for complete core analysis tests, was constructed and used initially on a Standard Oil Company of California-Humble Oil & Refining Co. well, on the

Standard-Humble Summerland State lease being drilled from a platform about 2 miles offshore near Santa Barbara, Calif. From this and subsequent tests using the portable equipment, substantial savings in coring costs could be made in cases where (1) it is desirable to have permeability and saturation data to prevent excessive penetration into a wet or transitional zone; (2) the company geologist or engineer can be relieved of the burdensome and time-consuming job of meeting each core; and (3) rig time can be reduced when immediately-available core analysis results will help in deciding whether or not electrical logging, fracing, formation testing or other services should be ordered out to the well.

Fast decisions save rig time. In exploratory wells and, frequently, in development wells, the operator is faced with the problem of determining what portion, if any, of the formation should be left open to production. This is a question which must be answered quickly, since any delay or misjudgement in this decision can be costly. One of the most effective means of answering this question is in having an analysis made of the core samples. Under normal circumstances on shore locations it usually is a simple matter to call out a mobile laboratory or to transport the cores to a nearby laboratory.

When drilling from an isolated land location, or from an offshore barge, island or platform; however, the situation often is altered, due, primarily, to the lack of convenient and inexpensive transportation facilities and the greater amount of time involved in getting samples to the laboratory. If there is no laboratory at the well site, and after the core is cut and brought to the surface, the cores must be described, sampled, then carefully packaged and preserved for transportation to the distant laboratory.

An important factor that must also be considered, is the fact that even after the cores have been analyzed and the data interpreted and reported, the confidential nature of the data usually necessitates personal delivery, unless private telephone or radio communication is available.

Quite often, on offshore locations, heavy seas or fog may ground boat and helicopter service, to cause delays which would add considerably to the cost of performing the analysis at shore-based laboratories. In some instances, the nearest service company laboratory may be hundreds of miles away. This, too, would add materially to the cost or may even result in an operator taking a chance on running pipe on a questionable sand and possibly obtaining an inefficient completion.

With these problems in mind, laboratory equipment recently was developed which was designed expressly for maximum portability and ease of setting up under a variety of conditions. The unique feature of this equipment, besides its portability (Figure 1), is that it is essentially of the same design as equipment used in larger, more permanent laboratories. This means that laboratory data meeting the rigorous requirements for reservoir engineering is now available at remote locations for guidance in well completions.

Equipment size reduced. When transporting laboratory equipment to offshore locations, modifications of certain pieces were necessary to reduce the size of some of them and to eliminate any possibility of fire hazards. The ASTM (Dean Stark) extraction flasks were reduced from the normal 500 ml size to the type shown in Figure 2 which requires only a few ml of extracting solvent. Another modification concerned the mounting of samples in pitch in metal cylinders for measurement of permeability. Normally, the flame of a torch is directed around the junctions between the pitch and the sample and at the metal in order to obtain an air tight seal. For offshore use, and in order to eliminate all open flames, a substitute method was devised using an electric heater.

Five suitcase-size boxes are used to transport the equipment to the location. Each box is light enough that it may be handled easily by one man (Figure 3). Usually, however, a crane or hoist is available for loading the equipment into and out of the boat. Due to the compactness and method of packing, only reasonable care is necessary in handling and transporting the laboratory.

At the well site, the apparatus can be set up in about an hour if facilities are conveniently located. The only requirements are suitable sheltered space, electric power and water. Compressed air is desirable but not essential since bottled air can be used. Ideal space requirements would be a desk or table about 3 x 4 feet in a room free from drafts. A small doghouse or house trailer is adequate for land locations. The portable laboratory has been operated satisfactorily in mud logging trailers.

Since weight and bulk have been reduced to a minimum, this equipment can be transported by air or other means to relatively inaccessible locations such as those often encountered in foreign drilling.

Personnel requirements vary according to the coring rate but, usually two men readily handle a routine core analysis job by working 8 or 12-hour tours arranged to coincide with the crew tour changes so that a special trip for boat or helicopter service is not necessary. The laboratory man oversees the removal of the core from the barrel, samples and describes the core, then performs the analysis. Since he is well qualified to handle these jobs, it usually is not essential for the oil company geologist or engineer to be on the job to meet each core, thus releasing him to perform other duties. The laboratory man is familiar with other tests in which the oil company might be interested, such as relative

About the Author

Robert E. Lampkin received a B.S. degree in chemistry from the University of Oklahoma in 1954. Since entering the oil business in 1943, he has done core analysis work throughout the Illinois Basin, Gulf Coast, Mid-Continent area, Rocky Mountains and the Pacific Coast. He served with the U.S. Army during World War II and was with the Marine Corps during the Korean conflict. Since 1952, he has been with Petroleum Technologists, Inc., in Montebello, Calif., and recently was transferred to the company's home office in Dallas where he assumed the job as general manager for the company's domestic and foreign operations. He is a member of AIME, API and ACS.

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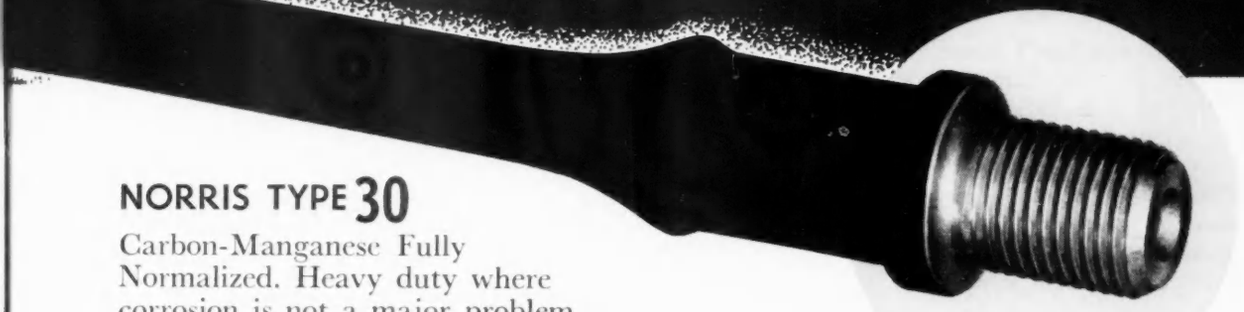

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permeabilities, capillary pressure curves, etc., thus he can collect samples for these tests to be done later since he knows the sample size requirements for his laboratory.

How are savings realized? Since each well presents its own characteristics and problems, it is difficult to say exactly what typical savings might be realized by the use of the well site portable laboratory. The following examples, however, are representative of typical experiences based on recent offshore location core analysis jobs:

Case 1: Core out at 2 a.m. Recovered 28 feet of sand.

A. (Using portable laboratory at well site) Core analysis engineer on the job samples the core in 30 minutes and has the oil-water ratios reported in 2½ hours. All oil sand, so no reason to disturb operator.

B. (Using shore laboratory) Company geologist or engineer alerted when core barrel is started out at 10:30 p.m. Drives 20 miles to heliport and helicopter makes special trip to well. One hour is required to sample core, with proper preservation, for transportation to the laboratory. Helicopter, which has been standing by at rig, carries geologist and samples back to land and geologist then drives to laboratory.

Cost: 5 hours plus mileage for geologist
2 hours helicopter time

Case 2: Core out at 10 a.m. Recovered 20 feet of sand grading to a mottled saturation near the bottom. Rig to be shut down pending results of core analysis.

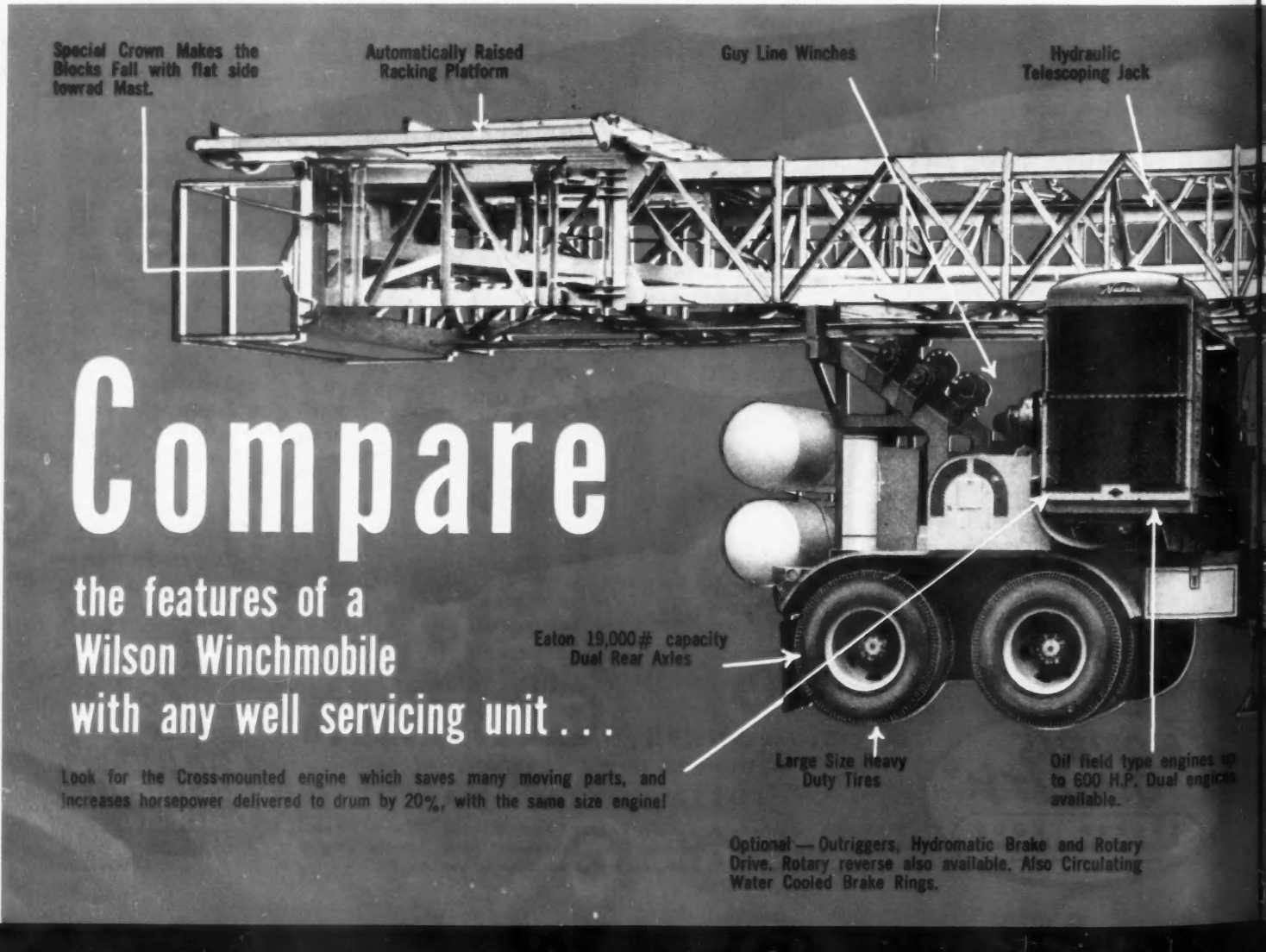
A. (Using portable laboratory at wellsite) Lab man samples core and reports oil-water ratios in 2½ hours.
Cost: 2½ hours rig time

B. Company representative samples as above. Delay due to sampling method and transportation is two hours, before samples reach the lab, plus 2½ hours for preliminary lab results.

Cost: 5 hours plus mileage for geologist
2 hours helicopter time
4½ hours rig time

The greatest saving to the oil company when using the portable equipment, is made when the coring is fast or when short cores are taken, especially if there is a thick section to be cored. Having a service company laboratory sample and analyze the cores amounts to having a consulting engineer or geologist on the job since it relieves the operating company's personnel from the sometimes monotonous task of core sampling and allows him to perform other normal duties.

The cost of having the core analysis laboratory at the wellsite compares quite closely with normal stationary laboratory prices on wells where extensive coring is to be done. When consideration is made for man and rig hours saved, the well site laboratory generally results in a considerable dollar saving for the oil company as well as being a matter of convenience. —**The End**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How major geologic features developed in Kansas

Continued from Page 124

there, the country has been elevated some 3,000 feet or more. Part of the elevation took place near the close of Cretaceous time.

It was only in the late part of Tertiary time that enduring sediments accumulated in western Kansas. The Ogallala Formation, as western Kansas Pliocene beds are called, is composed of material eroded from a former generation of the Rocky Mountains. Although now the top of the Ogallala is the High Plains surface, the country was not very high at the time of accumulation. Near the close of Tertiary time all of Kansas, it is believed, was being tilted eastward. The High Plains became high. Previously existing structures have been tilted, and hence comparatively recent movements, as well as ancient ones, have played a part in forming present day oil traps.

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About the Author

Dr. J. M. Jewett is senior geologist, State Geological Survey of Kansas. A graduate of the University of Kansas, he has taught geology at this university and at the University of Wichita, and was for one year curator of invertebrate collections at the University of Cincinnati. A native Kansan, he has spent much of the last 30 years investigating the geology of Kansas, especially stratigraphy of the Pennsylvanian and Permian. He is author of nearly 100 articles and books, including "Oil and Gas in Eastern Kansas" (three editions) and "Geologic Structures in Kansas."

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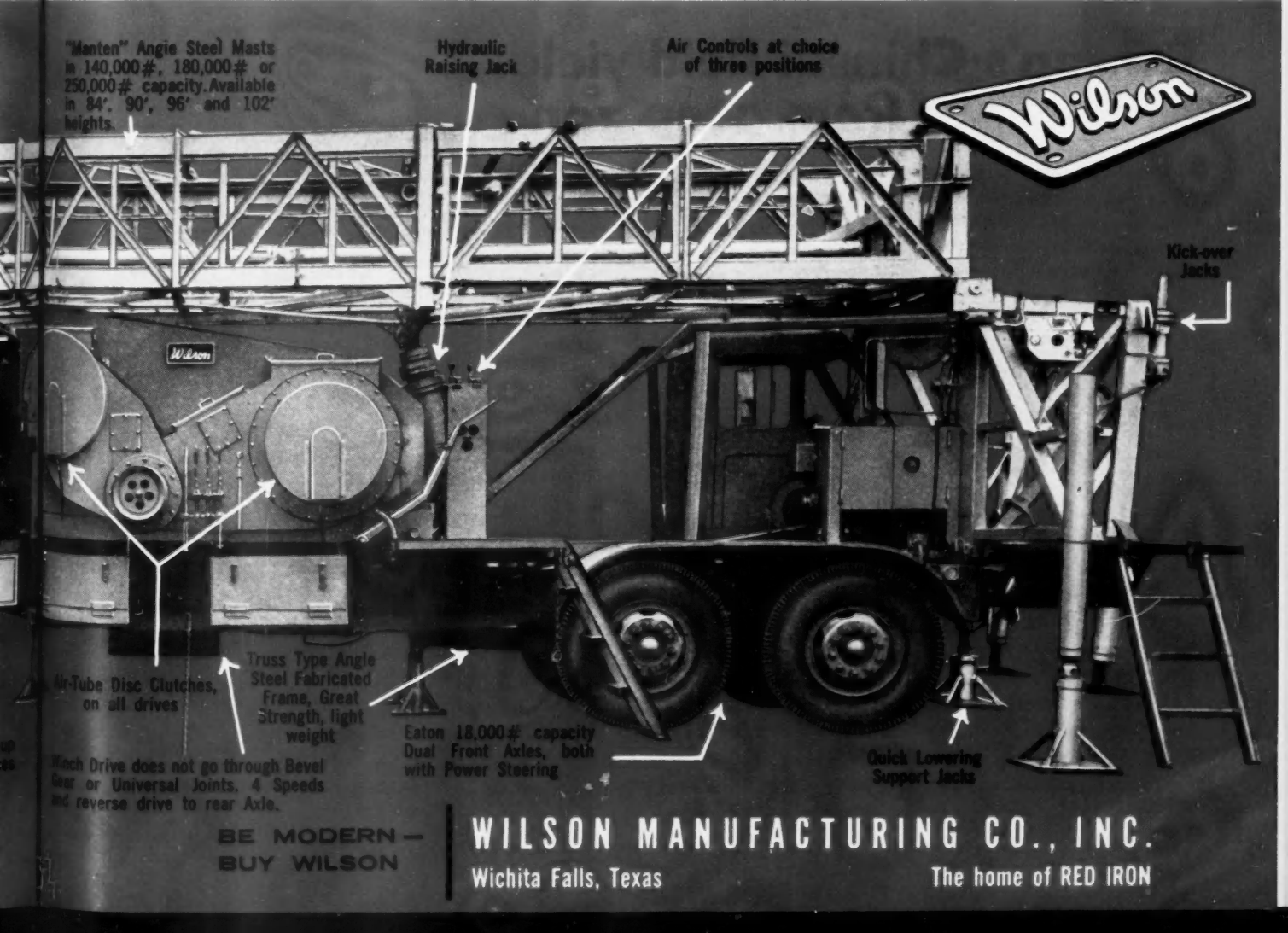
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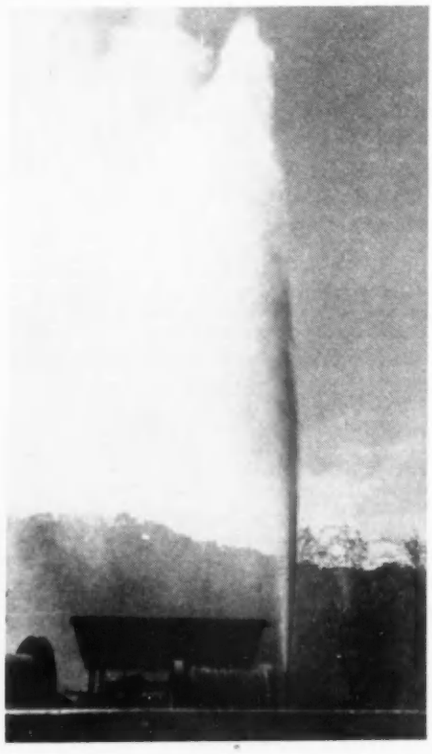

Chinsuit Well 38 (left) in northwestern Taiwan. It discovered a new deeper oil pay at 11,726-12,103 feet. Water and mud were ejected from Well 38 during testing (right). Gas and oil are produced from Miocene sandstone formation at 12,000 feet on the Chinsui anticline structure.

Taiwan's Chinsui field yields oil and gas from deep zone

Chinsui Well 38 of Chinese Petroleum Corporation has discovered a new, deeper oil and gas pay on the Chinsui Anticline structure in northwestern Taiwan (Formosa). Production tests of the deeper sands were in progress at the middle of November. The well flowed 3,500,000 cubic feet of gas and 65 barrels of API 44° gravity oil a day, on average, for the first three days.

Well 38 was selected as a deep zone test well after 12 years of production from shallow zones. The hole was deepened from 11,753 feet to 13,327 feet in July 1959. This is the deepest well in Taiwan.

The well drilled through five sandstone formations within the mentioned depths. Specific gravity 1.47 (12.3 pounds per gallon) mud was used during drilling below 12,100 feet in order to keep the well quiet. A 4½-inch liner was run and cemented in this deepened section of the hole.

The well was gun perforated with 74 shots between 11,726 feet and 12,-103 feet. Testing of the formation showed the bottom hole pressure to be about 7,250 pounds per square inch. A 5/32-inch bottom-hole choke and a 13/64-inch surface choke were used during the testing. Wellhead flowing pressure was indicated to be 1,500 pounds per square inch.

This is the first major discovery on this island since World War II.

Active drilling proceeds in Iran and Persian Gulf

National Iranian Oil Company's wildcat, Binak 1, in southern Iran, was completed late in 1959 as a discovery well, flowing from 4,000 to 6,000 barrels of oil daily from a Cretaceous formation. Total depth was 10,822 feet. The well is located on the Kuh-i-Bang structure, northwest of Ganaveh, and 20 miles inland from the Persian Gulf. (World Oil, August 15, 1959, Page 181 and map on Page 191.)

The Seacat Drilling Co. of Iran, S. A., affiliate of Southeastern Drilling Corp., Dallas, Texas, has signed a two-year contract with the Iranian Consortium to conduct exploratory drilling operations in southern Iran. A rig to be used consists of a hoist, three diesel engines, and two 700 hp pumps, together with all other necessary balanced equipment. It is capable of drilling to 18,000 feet.

The first well will be located 12 miles east of the town of Bandar Abbas. It is projected to 15,000 feet.

The rig was assembled and fully tested in Houston. A ship carrying the rig departed from Houston on Nov. 11, 1959. It was scheduled to arrive at Bandar Abbas around Dec. 10, 1959. All of the equipment, the drilling rig, camp houses, oil field trucks and road building equipment were due to be unloaded by ship's tackle onto lighters and moved directly to the beach.

In addition to the drilling contract, the entire Marine and Civil works contract is also to be handled by the drilling company. This includes construction of roads and the location, air strip, tank and warehouse construction, laying of water lines from the beach to the rig, off-loading the entire rig and delivery to the shore, construction of a 900-foot long Quay as a permanent facility, and providing the Marine transport for the shipment of all subsequent materials from Bandar Mashur to Bandar Abbas by barges or self-propelled vessels.

The first well was scheduled to be spudded approximately Jan. 10, 1960.

The Seacat Drilling Co. also owns and has had under contract for the past two years, two rigs in Iran for the Iran Oil Company. It also operates a mobile barge for Pan American International Oil Co. in the Persian Gulf, which in November 1959 was drilling below 2,000 feet in water depth of 127 feet. Projected total depth for this well will be approximately 14,000 feet.

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Active field development now under way in South Argentina

Within nine months after drilling began in early 1959, Pan American International Oil Co. had drilled more than 60 wells on its contract area in southern Argentina, and had produced more than 180,000 barrels of oil.

The company, which was the first to sign an oil development contract with Yacimientos Petroliferos Fiscales, the Argentine state oil agency, recently had 14 rigs operating, including 10 drilling and four on completion work.

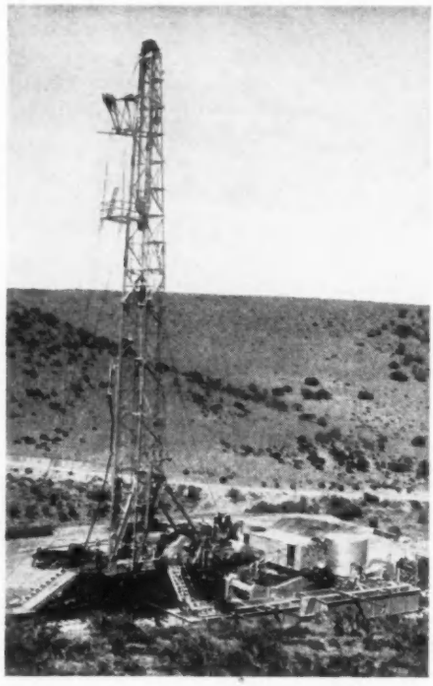
The rigs had drilled or were in process of drilling, 46 wells in Cerro Dragon, six in Canadon Grande and 11 in Anticlinal Grande—for a total of 63 wells since drilling commenced January 6, 1959. Pan Am International was also the first company to get operations under way in Argentina.

Pan Am International's contract with YPF, which was signed on July 21, 1958, stipulates that a minimum of 150 wells are to be drilled by the firm within the first two years from the date of contract signing. Of these, 120 are to be drilled in the Cerro Dragon-Canadon Grande area, and 30 in the Anticlinal Grande area. Cerro Dragon-Canadon Grande is approximately 40 miles west of Comodoro Rivadavia, while Anticlinal Grande is some 75 miles west of Comodoro.

The company said that it anticipated substantially exceeding the minimum drilling program called for in the contract within the allotted two-year period.

In addition to the development program, Pan Am International was drilling a deep wildcat at Anticlinal Grande, which was projected to basement. Basement was expected around 8,500 feet. Deep wildcats also were scheduled to be drilled to basement rocks in Cerro Dragon and Canadon Grande in 1959.

Wells in Cerro Dragon reached a depth of between 4,250 and 6,660 feet and took from nine to 15 days to drill. At Anticlinal Grande, wells were drilled to about 3,300 feet and required about 12 days. The company expected drilling times to be reduced when the crews became more experienced in handling the portable rigs sent to Argentina for the development program.



A drilling well in the Cerro Dragon area of southern Argentina, where Pan American International Oil Co. is carrying out development operations under contract with YPF. Terrain and vegetation are similar to many areas of West Texas.

Actual oil production by Pan Am International was about 3,100 barrels per day in October, 1959. That was the volume which could be handled by an existing YPF pipeline from Cerro Dragon to Caleta Cordova, a YPF pipeline terminal on the Atlantic coast near Comodoro Rivadavia. YPF has installed an additional pump at the Cerro Dragon station. It will increase the capacity available to Pan Am production to about 6,300 barrels daily.

Pan Am International's producing capacity from wells completed up to October 1, 1959, was about 10,000 barrels per day.

The company was building a new pipe line from Anticlinal Grande through Cerro Dragon to Caleta Cordova, with completion scheduled for about February, 1960.

The line will be 12½ inches in diameter from Anticlinal Grande to Cerro Dragon and 14 inches from Cerro Dragon to the coast. Total length of the line is approximately 85 miles. It will have an initial capacity of about 50,000 barrels daily, with provision for increasing capacity by the addition of pumping stations.

By the time the new pipe line is completed, Pan Am International expects to have a producing capacity of over 12,500 barrels daily, which will be transported through the line. Producing capacity is expected to increase to about 35,000 barrels daily by the end of 1960.

All oil produced by Pan Am International is delivered to YPF for use within Argentina.

Pan Am International's operations in Argentina are headed up by I. H. Hughes, formerly of Tulsa, Oklahoma, who is general manager of Pan American Argentina Oil Co., Pan Am International's operating subsidiary in Argentina.

Pan Am International is the overseas subsidiary of Pan American Petroleum Corporation, an affiliate of Standard Oil Company (Indiana).

Conoco-Cities Service to explore vast Senegal and Mauritania acreage for oil

Continental Oil Company and Cities Service Company jointly have concluded contracts for oil exploration on more than 10,000,000 acres in Senegal and Mauritania, West Africa.

In Senegal, Conoco and Cities Service will join two French companies, Societe Africaine des Petroles (SAP) and Compagnie de Participations, de Recherches et d'Exploitations Petrolieres (Coparex), in exploring for oil in the St. Louis and Richard Toll areas on concessions totaling more than 3,400,000 acres.

In Mauritania, Conoco and Cities Service will be associated with SAP and the Societe de Recherches et d'Exploitation de Petrole (Eurafrep) on a concession covering approximately 7,300,000 acres.

In Senegal, Conoco will own a 25 percent interest in the concessions, Cities Service, 24 percent, and the French companies, 51 percent. In Mauritania, Cities Service will own a 25 percent interest, Conoco, 24 percent, and the French companies, 51 percent.

Your industry at work

A monthly roundup of items of interest about people, companies and associations

Schoolroom in the Sand

Shell geologists from many parts of the world are making the Gulf Coast their classroom during a seminar conducted by scientists of Shell Development Company's Exploration and Production Research Division in Houston. Above, the group assembles on the Galveston Island beach to hear Dr. H. A. Bernard, with microphone, describe various features of the island's geologic structure. The seminar is designed to keep Shell's operating geologists up-to-date on late research findings, and to permit exchange of ideas and knowledge between geologists from different parts of the country. The Gulf Coast was chosen for the seminars because it provides an excellent sample of sedimentation processes which are responsible for formation of much of the world's underground oil reservoirs.

S. R. Casey Forms New Oil Property Management Corp.

S. Russell (Pat) Casey, Jr., has formed a new corporation, Pat Casey & Associates, in Houston. The purpose of the company is to provide an organization which will furnish management of operations and funds to be committed to the oil and gas exploration business.

S. R. Casey

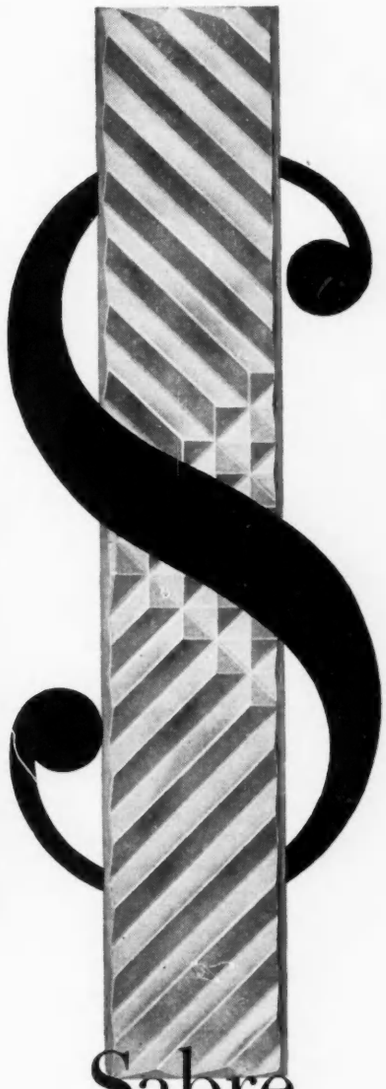
Officers of the corporation are: Casey, president and treasurer; Dudley Sharp, Jr., vice president in charge of management; Loren E. Brown, vice president in charge of finance, and Heber Stone, secretary-manager for the Land Department.

Gene Reid Drilling, Inc., Moves to New Headquarters

Gene Reid Drilling, Inc., a subsidiary of Occidental Petroleum Corporation, has moved to a new location in Bakersfield, Calif., taking over the former facilities of the Kern County Land and Water Company on the Stockdale highway. Former address was on Pierce Road.

The new location includes six fenced-in acres and complete facilities. Structures on the ground have been completely reconditioned. Five new offices were added. The area also includes garages, pipe and rig storage and all operational facilities.

Occidental's field, geological and exploration offices have been combined with those of Gene Reid Drilling. Main offices for the entire company, including Reid Drilling, is at Occidental's headquarters in Los Angeles.



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Floating Medical Center Donations

Harold S. Skinner, assistant to the president of Continental Oil Co., is shown presenting the first pledges made by U.S. Oil Co. toward the founding of the volunteer-operated floating medical center, SS HOPE, to Dr. Wm. B. Walsh, president of the People-to-People Health Foundation, Inc. Harry Goldberg, (far right), representing AFL-CIO President George Meany, a director of Project HOPE, looks over Skinner's shoulder and gives the well-done sign. Joe Gueting, Jr. (far left), vice president of the unique medical ship project, reviews the checks with Dr. Walsh. Leonard F. McCollum (not shown), president of Continental Oil Co., is chairman of a small informal committee within the oil industry seeking to raise funds among oil companies to guarantee a year's operation of the floating medical information exchange center. The ship, to be outfitted for the People-to-People Project, is the mothballed Navy hospital ship, USS Consolation.

Mobil Oil Company Picks 16 Cities as New Headquarters

Mobil Oil Company has selected 16 cities across the land as new district headquarters in a major redistricting program of the exploration and producing department.

The changes will take place gradually in the next few months. The 16 cities selected, six of them in Texas, will have headquarters offices within the jurisdiction of Mobil's new Houston, Midland, Texas, and Denver exploration and producing division offices. These offices were announced recently by Mobil Oil, the operating company in the U.S. and Canada of Socony Mobil Oil Company, Inc.

The cities chosen as district headquarters in the Houston division, headed by Vice President Henry L. Waszkowski, Jr., are: Exploration and producing, Corpus Christi, Texas, and Shreveport, La.; producing only, Victoria, Texas, and Lafayette, La.; exploration only, New Orleans and Houston. The Houston division stretches from the Rio Grande to the Atlantic Ocean, covering the Gulf Coast and East Texas and all of Arkansas, Louisiana, Tennessee, Mississippi, Alabama, Georgia, North and South Carolina and Florida.

In the Midland division, headed by Vice President R. D. Hanley, these cities were named as headquarters: Exploration and producing, Midland and Wichita Falls, Texas; producing only, Lubbock, Texas, and Hobbs, N.M.; exploration only, Roswell, N.M. This division includes Texas except for the Gulf Coast and East Texas and all of New Mexico except for the San Juan Basin.

In the Denver division, headed by Vice President E. V. Watts, the following were named as district offices: Exploration and producing, Oklahoma City, Wichita, Kan., and Casper, Wyo.; exploration only, Pittsburgh. The Denver division extends from the Rocky Mountains to the Atlantic Ocean, covering all or parts of Colorado, Oklahoma, Kansas, Montana, Wyoming and all midwestern and eastern states north of the Houston division.

Halbouty Urges Mandatory Pooling Law for Texas

A new Texas law which would require mandatory pooling on established spacing patterns in Texas oil and gas fields was advocated by Michel T. Halbouty at a joint meeting of the Houston API chapter and Gulf Coast Section of the Society of Petroleum Engineers of AIME.

Halbouty differentiated between mandatory pooling, which he identified as being on an established unit basis, and fieldwide compulsory unitization. He said, however, that compulsory unitization, under federal law, was a strong possibility in the United States unless steps were taken to correct present inequities in conservation laws and regulations.

MAGCOBAR TECHNOLOGY
cuts the cost of drilling. At Magcobar, drilling mud is a scientifically designed combination of chemicals engineered to meet your drilling conditions as they occur and to result in the lowest possible over-all drilling cost. And with Magcobar you get the right drilling chemicals *used right*—backed by chemists, reservoir engineers, and laboratory facilities. All of this . . .

HELPS OPERATORS
with drilling fluids that reduce or prevent damage to the pay. Often, completions are quicker, production higher, and there is less need for expensive stimulation work. Because of Magcobar's advances in drilling mud technology, today's wells are worth more to the operator and cost less to produce than similar wells only a few years back. But Magcobar also . . .

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to cut total drilling costs by using the right mud products *right*. Magcobar products and engineering in partnership with the contractor result in faster drilling, greater safety, and a more profitable operation. Magcobar technology helps by reducing friction to increase the life of mud pump parts, reducing torque, swivel wear, load on chains, rotaries, drive system, and engines. Helps . . .

TO MAKE FASTER PENETRATION
to cut the cost per foot of drilling. Faster penetration means savings in bits, fewer round trips, and fewer operating hours. But the problem of fast drilling is only partially one of chemicals. That is why more and more drillers call Magcobar engineers before starting. This combination of Magcobar products and planned engineering means faster drilling, greater safety, and higher profits.

Here's how Magcobar cuts drilling costs around the world . . .

T-8®
compound is a one-package additive which builds and maintains a shale control mud. Proper use results in lower mud cost, greater hole stability, and more uniform properties.

BIT LUBE
is a slightly viscous, oily fluid which gives to drilling fluids many of the properties of an extreme pressure lubricant. Bit Lube protects bit bearings, to increase bit life, and reduces hole friction, resulting in faster penetration with fewer round trips.

MAGCONATE
is a powerful emulsifier for oil-in-water emulsions. It allows the use of higher bit weights without balling problems. It forms a very tight emulsion, making for lower filtration loss and a reduction in surface tension of the filtrate.

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SPERSENE
a chemically modified lignosulfonate, is a highly effective thinner in gyp, lime, and salty muds. It is readily soluble in fresh or salt waters. It lowers viscosity more effectively, at less cost, than many of today's leading thinners.

LEATHER-FLOC®
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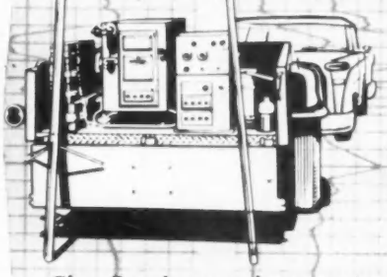
Geo-Logger



The Geo-Logger is a portable one-man operated unit that goes everywhere. It is designed to record several different type logs. The field proven models range from 750' to 6000'.

FOR THE FOLLOWING PROGRAMS:

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TYPE OF LOGGING AVAILABLE:

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Men in the industry

P. J. Parker

W. F. Martin

H. D. Brookby

John Getgood

Paul J. Parker, a director and formerly secretary and assistant treasurer, was elected president, international, by the directors of **Phillips Petroleum Company,** to head the newly formed department to consolidate its activities outside the United States. **W. F. Martin,** formerly assistant secretary and assistant treasurer, was elected to succeed Parker. The division and their managers are: exploration and production, **Harry D. Brookby;** sales and development, **John Getgood,** and operations, **W. L. Phillips.**

W. L. Phillips

Glenn A. Campbell has been appointed general manager of Drilling and Production for **White Eagle Overseas Oil Co., Inc.,** Manila, Philippines.

Donuil M. Hillis has been elected president and a director of **Four Corners Oil & Minerals Co.,** replacing **Edward A. Koester** who has resigned to re-enter private consulting practice. Also elected a director of Four Corners was **Earl R. Howsam** who replaces **Dr. Edward L. Clark,** recently appointed director of natural resources for the state of Colorado.

Fred L. Gaye has been transferred from **Delta Drilling Company** to **Delta Marine Drilling Company** and assigned as superintendent of Offshore Operations. **Foster T. Manning,** who has been employed by both Delta firms, now bears the titles of division engineer of Delta Drilling Company, and marine engineer of Delta Marine Drilling Company.

Arthur A. Curtice has resigned as president and general manager of Signal Oil and Gas of Venezuela to return to his consulting practice in New York City.

Forrest M. Darrough has resigned as vice president and general counsel for The Carter Oil Company to accept an appointment as associate general counsel of the recently organized **Humble Oil & Refining Company of Delaware,** Houston.

Angus A. Davidson, general attorney, and **Loren L. Ware,** vice president for exploration, have been named coordinators for **Sinclair Oil & Gas Co.** Davidson will serve as coordinator of legal, lease, tax, claims and FPC matters. Ware was named coordinator for geological, geophysical, land, scouting and conservation and proration.

R. Gordon Humphries has been appointed petroleum engineer in the Calgary Oil and Gas department of the **Toronto-Dominion Bank.**

Daniel A. Painter has been employed as staff geologist, Geological Department, and **John W. Baker,** has joined the Land Department, of **Delhi-Taylor Oil Corporation.**

PERFORATE TUBING IN THE WELL

KINLEY TUBING PERFORATOR

M. M. Kinley Company Licensees

ABILENE, TEXAS—Hudson-Eads, Inc....OR 2-5331
ANACO, ANZOATEGUI, VENEZUELA
Anzoategui Wire-Line Service, C. A.
BAY CITY, TEXAS—J. P. Graham.....CI 5-4528
BEAUMONT, TEXAS
Assoc. Eng. & Eqpt., Inc.....TE 5-7046, ZF 8-2023
CABIMAS, ZULIA, VENEZUELA
Wireline Engineers, S. A.
CASPER, WYOMING—C. A. White.....3-5264
CORPUS CHRISTI, TEXAS—Tolle, Inc...TE 5-5367
FARMINGTON, NEW MEXICO
B & R Service, Inc.....DA 5-2393
FORT MORGAN, COLORADO—C. A. White....919
GLENDIVE, MONTANA—C. A. White...EM 5-3833
HOBBS, NEW MEXICO
Horne Well Service Co.....3-5396
HOUMA, LOUISIANA—Cameo, Inc.....7330
HOUSTON, TEXAS
Assoc. Eng. & Eqpt., Inc.....CA 5-1103
HOUSTON, TEXAS
Mid-Western Well Ser. Co.....RE 4-4262
HOUSTON, TEXAS
Long Line Production Co.....GR 3-5739
LAFAYETTE, LOUISIANA
Assoc. Eng. & Eqpt., Inc.....CE 5-6770
Cameo, Inc.....CE 5-3124
LIBERAL, KANSAS—Rainbo Service...Main 4-3598
MIDLAND, TEXAS
Luccous Service & Eqpt. Co.....MU 2-1631
HOUMA, LOUISIANA
Assoc. Eng. & Equip. Inc.....UP 2-0347
ODESSA, TEXAS
Cameo Wire Line Service, Inc.....FE 2-6497
OKLAHOMA CITY, OKLAHOMA
Rainbo Service Co.....ME 4-2131, ME 4-0105
PETTUS, TEXAS
Eddie Jones Eng. Co., Pettus 16, Beeville, FL 8-1218
SHREVEPORT, LOUISIANA—Cameo, Inc....8-3615
VICTORIA, TEXAS—Cameo, Inc.....HI 3-9521
WHITTIER, CALIFORNIA
Kline Wire Line Co.....OX 3-2731
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322-8584, 322-1792, 767-8727, 723-4690, 767-3793

Out-of-Towners Visit New York NOMADS

The New York Chapter of NOMADS held its annual monthly party recently and there was a large assembly of out-of-town guests. Seated left to right: F. A. Chapman, Aramco Overseas Co., Australia; A. K. Baebel, Hughes Tool Co.; J. Birks, British Petroleum Co., Ltd.; B. Beverly, Arabian American Oil Co.; and A. A. Ashton, Continental-Emsco, Dallas. Standing left to right: R. P. Gaylord, Wagner Morehouse, Inc., visiting NOMAD from Los Angeles; G. A. Caragilino, YPFA; W. R. Brennan, Arabian American Oil Co.; H. R. Warman, Sinclair Oil Co.; and J. E. Skipworth, Lucey Export Corporation.

Eugene L. Maxwell, regional exploration manager at Denver, has been named to the newly created position of director of Domestic Exploration, Houston, for **Lion Oil Company, Division of Monsanto Chemical Company.**

Hugh W. Swan has been promoted to production foreman at Hobbs, N. M., for **Tennessee Gas and Oil Company,** a division of **Tennessee Gas Transmission Company of Houston.**

M. McDonald

Marshall McDonald, president of an investment company and insurance company in Houston, has been named vice president and financial coordinator for **Sinclair Oil & Gas Company** in Tulsa. He will coordinate the accounting, treasury, economics, insurance and data processing departments.

Forrest N. Shumway has been appointed secretary of the **Signal Oil and Gas Company.** He has been a member of Signal's legal staff since 1957. He became assistant secretary the same year and was named a director in January 1959.

W. H. Hammond has joined **Texstar Petroleum Company,** a division of **The Texstar Corporation,** as petroleum geologist and manager of exploration activities.

Edward A. Koester has resumed the practice of consultant, particularly on the geological problems of the Rocky Mountain and Mid-Continent regions. His temporary offices are located in Denver.

D. A. Butler, Phillips Petroleum Co., has been elected president of the recently organized Tulsa chapter of the **Society of Professional Well Log Analysts. Wayne Ranta, Sinclair Oil Co.,** was named technical first vice president, and **E. V. Landrigan, Cities Service Oil Co.,** was named secretary-treasurer.

James C. Denton, Jr., has resigned as a senior attorney for Sunray Mid-Continent Oil Co., to join the legal staff of **Pan American International Oil Co.,** in New York City.

Harry K. Armstrong has been employed by **W. E. Stiles Engineering, Inc.,** as superintendent of Production Operations in the Oklahoma area. He was formerly superintendent of the Siminole District for The Atlantic Refining Company.

Leslie D. Burritt has been appointed director of the construction engineering division of **Esso Research and Engineering Company.** He succeeds **Allen J. Ely** who retired.

Robert F. Miller has been appointed director of Records and Statistics of **Gulf Oil Corporation's** Crude Oil Supply.

P. D. Collins and **C. J. Angulo** have been elected to the board of directors of Esso **Standard (Libya) Inc.,** exploration and producing affiliate of **Standard Oil Company (New Jersey).** Together with **Robert A. Eds,** president and director, and **H. W. Brown,** executive vice president and director, Collins and Angula will make their headquarters in Libya.

J. Arthur Kelly has been appointed general attorney for the United States and Canada for **Mobil Oil Company,** the operating division of **Socony Mobil Oil Company, Inc.**

A and B TUNGSTEN CARBIDE

for Hard Facing of

- **Drilling Bits**
- **Tool Joints**
- **Rotary Shoes**

When applied to tool joints, rotary shoes, rock bits and underreamers, A and B Tube Metal gives the oil industry the hardest, toughest, most uniform deposit of abrasive-wear resistant surface it is possible to obtain with manual torch or arc.

AVAILABLE SIZES*

Size of Rod	Tungsten Carbide Mesh Size
5/32 x 15"	30-40, 40-80, 40-100, 30-dn
3/16 x 15"	20-30, 30-40, 40-80, 40-100, 30-dn
1/4 x 15"	10-16, 20-30, 30-40, 40-80, 30-dn

BULK METAL

A and B Bulk Metal is clean, crushed tungsten carbide particles of uniform high quality, designed to give hard, non-porous, wear-resistant surfaces. Available in the following screen sizes:* 4-8, 8-10, 10-20, 30-40, 40-100, 10-200, and 200 dn.

*Special sizes available on request.

A AND B

Metal Mfg. Company, Inc.

Mfrs. of Tungsten Carbide

P. O. BOX 13125 HOUSTON 19, TEXAS

New Visco Well-Treating Formula Penetrates, Loosens, Disperses Deposits in Tanks, Lines, Tubing

Lowered pumping pressure, Tripled production, Dispersed solid paraffin... Among Spectacular Performance Results with Visco 1111

Visco 1111, on the job in oil and gas producing wells, water-injection wells and salt water disposal systems, has amazed even the most optimistic with its performance and economy. Here are a few examples of how it works to penetrate, loosen and disperse deposits of paraffinic-asphaltic compounds, carbonate scale, sodium salt deposits, iron compounds and other materials causing loss of production.

Cuts Pumping Pressure 175 psi

Injection pressure was 325 psi on a water injection well. Foreman believed pressure was due to a tight formation, but agreed to a test of Visco 1111. Pressure is down to 150 psi—and staying there, with one-gallon-per-day dosage of Visco 1111.

7-Well Cleanup Nets 60 bbl. Increase

Sticking pumps, caused by scale build-up, were causing frequent rod-pulling jobs on a 7-well East Texas lease. Visco 1111 cleaned up the pumps and tubing, upped production 60 bbl. per week. Company now using Visco 1111 on all their wells in East Texas.

Stopped Reperforating Need

On another East Texas lease, wells making high salt water with low-gravity oil tended to scale up and require periodic reperforation. Visco 1111 was given a trial on a well making only 3 bbl. oil and 20 bbl. water a day . . . quickly jumped daily production to 23 bbl. oil and 60 bbl. water. Cost: only $23.50 . . . as against $300 to reperforate.

Solid Foot of Paraffin Gone

A 500 bbl. tank contained 470 bbl. oil and a 12-inch paraffin bottom—so hard that an oil thief would not drop through. 5 gallons of Visco 1111 and 48 hours later the tank went on at 0.5% B.S. & W., *and no bottom at all.*

Easy to Use, Too!

Visco 1111 has excellent blending characteristics under a variety of field conditions, and does not gel when added to water. Your Visco Service Man will be glad to help you determine proper Visco 1111 dosages for best performance and economy on your leases. Ask him about this new well-treating product . . . or write us, today, for detailed product data.

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Visco®
. . . Serving the Oil Industry through Practical Applied Science

Visco CHEMICALS
Visco SERVICES

Men in the industry

PEMEX Officials Guests at NOMADS Luncheon

These Petroleos Mexicanos officials were on hand during the recent API meeting in Chicago and were guests at the NOMADS luncheon. Left to right, Serapion Fernandez, Fernando Padilla, Director General Gutierrez Roldan, Antonio Garcia Rojas, Alfonso Barnetche, Rafael Ortiz Mena and Carlos L. Corcuera.

Don R. Greenwalt, field engineer, has been transferred from Illinois to Victoria, Texas, for **Tidewater Oil Company.**

Richard N. Knokblock, district engineer for **Texaco Inc.,** has been transferred to Wichita, Kan., from Illinois.

M. K. Doumani, California oil operator, is the head of the new management team which has acquired **The Dunn Brothers Petroleum Corporation.** The company will be known as **Kent Petroleum Corporation** and headquartered in the First Federal Savings and Loan Association Building, Hollywood.

F. J. Allen, Jr., has been appointed assistant to the vice president of **Delta Marine Drilling Company.** Allen has been assistant division manager for Gulf Coast Division of **Delta Drilling Company** for the past two years.

Donald J. Buckley has been appointed a senior research associate with **Esso Research and Engineering Company. Dr. Wladmir Philippoff, Robert Henry Salvesen** and **Ernest V. Haines** have joined the staff of Esso.

Henry A. Witcher has been promoted from division superintendent for gas and oil products, Houston, **Sinclair Oil and Gas Company,** to superintendent of operations, Tulsa. **Zed D. Grissom,** division exploitation geologist in the Tulsa Division has been named manager of Sinclair's Anchorage, Alaska, district office. He succeeds **Robert L. Porter. Clarence H. Unruh,** intermediate geologist at Ardmore, Okla., also has transferred to Anchorage.

Claude Wild, Jr., has been appointed legislative representative in Washington, D. C., for **Gulf Oil Corporation.**

L. L. Parish, district exploration superintendent in the Exploration Department for **Tennessee Gas and Oil Company,** a division of **Tennessee Gas Transmission Company,** has transferred from Roswell, N. M., to Oklahoma City, succeeding **James D. Giles,** who has resigned. **Eugene McElvaney, Jr.** district exploration superintendent at New Orleans transferred to Roswell replacing Parish.

Robert C. Quails, petroleum engineer, has been employed by **Sage Oil Company** as vice president and general manager of Production and Exploration.

W. W. Moore, division geologist at New Orleans, has been advanced to assistant division manager at Houston, for **Texaco Inc.** Also, **R. B. Palmer,** assistant division geologist, Midland, Texas, advanced to division geologist, New Orleans. **Kenneth E. Myron,** geologist on the general manager's staff, promoted to staff geologist of the vice president's office, New York, Domestic Producing Department.

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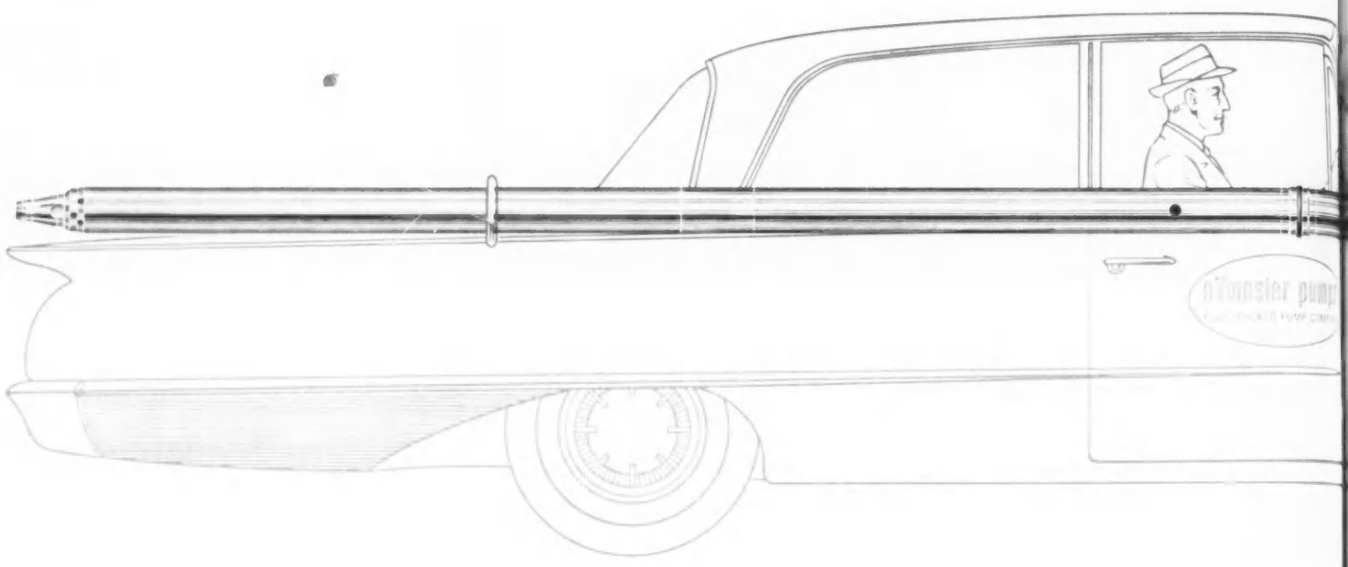
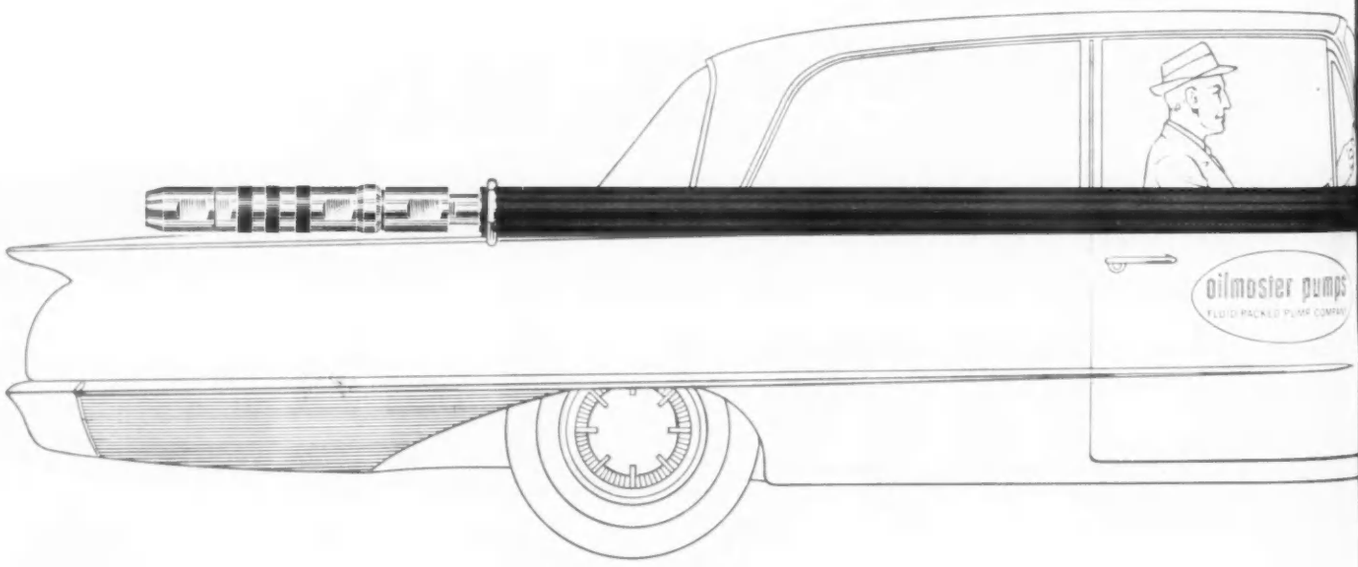
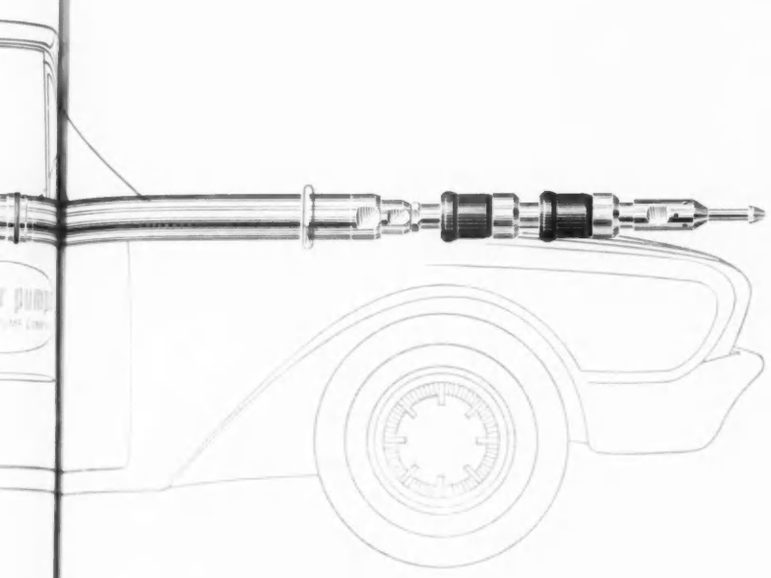


Which Car has the R

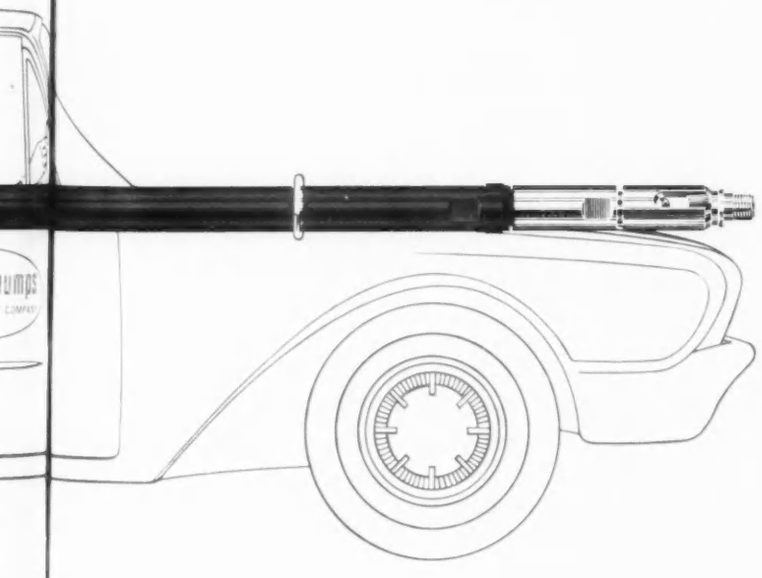


Oilmaster—the acknowledged leader in p



Guess again—This Fluid Packed Pump Co. field service car is delivering one of the new OILMASTER Subsurface Hydraulic Production Units. From outward appearance rod pumps and hydraulics look alike, but keep watching these OILMASTER cars closely and you will see an increasing number carrying the hydraulic. If you are operating subsurface hydraulic pumps now, or are considering a future hydraulic installation, ask your Oilmaster sales representative about the many outstanding features of this unit. Look at the specification sheet and compare the capacity, the pressure requirements, and the variety of models with other subsurface hydraulic production units. Then ask your Oilmaster sales representative about field service and on-the-spot repair in well equipped, strategically located pump shops.

eRod Pump?



You're right, it's this one! It's the same Fluid Packed Pump Co. field service car, but on this trip it is carrying an OILMASTER Sucker Rod Pump—The pump that has set the standard by which other pumps are judged. If you are talking hydraulics with your OILMASTER representative, don't forget he also can help you with a complete line of rod pumps and accessories including such OILMASTER firsts as the Three Tube Fluid Packed Pump, the One-Piece Hardened and Honed Barrel, the incomparable Unit Barrel, the Independently Landed Parallel String for Dual Zone Installations, the Ratio Compound Pump, the Tungsten Carbide Seat and Ball and the Vertical Setting Pump Anchor.

For more information on the new OILMASTER Hydraulic write for Bulletin E-5903.

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Men in the industry

R. E. Hunt, geologist on the general manager's staff, was appointed assistant division geologist of the Midland, Texas, Division.

William W. Wicks has joined the Public Relations Department of **Standard Oil Company** (**Indiana**) as supervisor of field services.

Joseph A. Kornfeld, Tulsa consulting petroleum engineer and geologist, has organized **Kornfeld International,** Tulsa consulting firm offering geological, geophysical, economics, and engineering services on foreign oil concessions. Auxiliary offices also will be opened in Denver, New York and London.

A. A. Buzzi

R. K. Burns

A. A. Buzzi has been named financial vice president of **Shell Oil Company.** Buzzi, who was comptroller, will succeed **A. G. Schei** who has retired. **R. K. Burns,** assistant controller and assistant treasurer of **Shell Chemical Corporation,** will succeed Buzzi.

Paul Wollstadt has been named to the newly created position of vice president, Employe and Public Relations, by **Socony Mobil Oil Company.** He was assistant to the chairman of the board.

Alexander Bogrow, has been named to head the new Zurick, Switzerland, office that has recently been opened there by **Arthur D. Little, Inc. Richard A. Stephen** will assist Bogrow.

William J. Scott has been appointed district superintendent of **Tidewater Oil Company's** East Texas District. He will make his headquarters in Kilgore, Texas.

D. S. Bodie, unit superintendent, **R. P. Hemphill** and **Don Presley,** assistant unit superintendents, **Carl Hefner,** unit engi-

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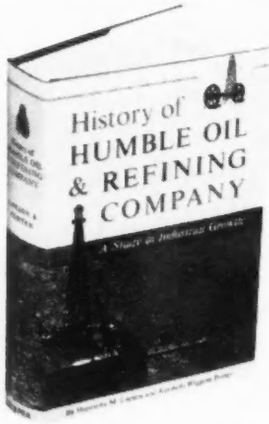

History of Humble Oil AND Refining Company

A STUDY IN THE GROWTH OF AN INDUSTRY

By HENRIETTA M. LARSON and KENNETH WIGGINS PORTER

Starting with the era of the fabulous Spindletop field, this history of Humble Oil shows how the company pioneered new concepts and techniques through the years to meet new problems and opportunities. Published during the Oil Centennial.

32 pages of photographs; 20 maps and charts; 16 pages of tables.

$7.50 *at all bookstores*

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VALVES

Men in the industry

neer, **Tom Kemmerling,** unit clerk, and **C. L. Barrett, T. F. Gray, Cecil Smith** and **G. L. Goodwin,** unit foremen, have been designated to operate **Cities Service Oil Co.'s** Northeast Purdy waterflood unit in Southern Oklahoma.

Franklin G. Spain will move from New Orleans to Dallas to head the land activities of **Diversa, Inc.,** which has recently centralized all Land Department activities in Dallas.

Michel T. Halbouty, Houston independent oil man, has been named to the newly created position of chairman of the board of the **Continental Bank & Trust Company,** Houston.

Edmund Dechard, formerly assistant comptroller for **Magnolia Petroleum Company,** has been appointed manager of Exploration and Producing Accounting of **Mobil Oil Company.**

W. J. McBride, formerly geologist with Humble Oil & Refining Company, has joined **D. R. McCord and Associates, Consultants,** Meadow Building, Dallas, to take charge of domestic geological operations.

Johnny Mitchell

H. M. Frank

Johnny Mitchell, independent oil man, has been named president and a director of **Jade Oil Company of California.** Other officers elected are **Harry M. Frank** of El Paso, board chairman and chief executive officer; **H. L. Leach** of Denver, vice president and treasurer; **J. Roy Derrick** of Midland, Texas, vice president; **Paul A. Smith** of Houston, secretary, and **B. F. Clark** of Houston, assistant treasurer. Directors include **Fred S. Thomson** of Los Angeles, **Royal M. Galvin** of Beverly Hills, Calif., and **Henry Beissner** of Houston.

R. (Dick) Steinhorst, Jr., has organized **S.O.S. (Steinhorst Operators Service)** in Lafayette, La., to furnish field supervision and management for drilling operations and producing properties.

James W. Swanson has joined **Mule Creek Oil Company** at Billings, Mont. He succeeds **Robert Gosman** who resigned to join **MKM Oil Company** at Casper, Wyo.

William H. Price has been named a vice president by **Cities Service Petroleum, Inc.,** a subsidiary of **Cities Service Company.**

G. D. (Dan) Almen, Jr., vice president and manager of Midland, Texas, Division of **Sinclair Oil & Gas Company,** has

G. D. Almen, Jr.

R. L. Elston

transferred to the New York offices of **Sinclair Oil & Gas Corporation. Robert L. Elston,** assistant manager of the Midland Division, was elected vice president and manager of the Midland Division to succeed Almen.

David F. Edwards, manager of the Bayonne (N. J.) refinery of **Esso Standard Oil Company,** has been invited to join the new **Humble Company** where he will become employe relations manager.

John F. Richardson has been named district engineer at Seminole, Okla., for **The Carter Oil Company. Gerald R. Gilbert** succeeds Richardson on the Tulsa staff. **Joe T. Taylor,** succeeded by Richardson, transferred to Purcell, Okla., replacing **K. H. Larsen** as district manager. Larsen is on temporary assignment with **Jersey Production Research Company,** also a Jersey Standard affiliate, in Tulsa.

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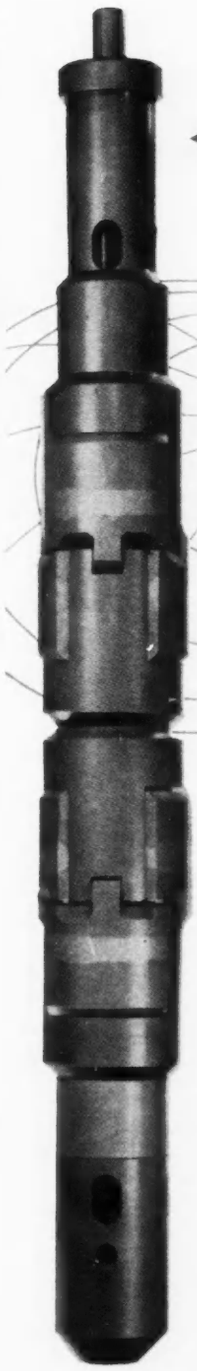

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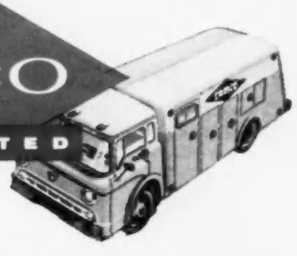

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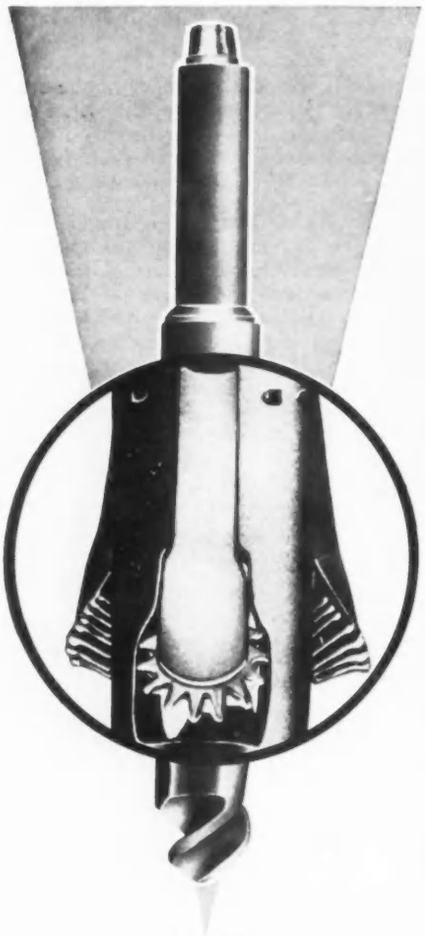

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Associations

International Guests of Houston NOMADS

International guests present at a recent meeting of the Houston NOMADS included: (front row, left to right) J. Koller, R. Liebl, and R. Oberhauser, Hubner-Mayer, Vienna; C. J. Panzer, Dowell, Germany; Walter Reisinger, Mobil-Austria, Vienna, and Basilio Monticelli, Y.P.F., Buenos Aires. (Second row, left to right) Hermann Sproker, O.M.V., Vienna; F. L. Griffith, Gulf Oil of Libya, Tripoli; A. Watson, Qatar Petroleum Co., Dukhan, Qatar; R. C. Reed, International Petroleum Co., London; Mario Lafont, Y.P.F., Indalecio Pelaez, Y.P.F., Buenos Aires, and H. L. Tu, Chinese Petroleum Co., Formosa. (Third row, left to right) J. N. Biron, Bobest Engineering Co., Longon; J. E. Berry, A-Z Export, Maracaibo; Mano R. Gonzales, Y.P.F., Buenos Aires; J. M. De la Garza, Perforode Latina, Mexico City; H. D. Hoopman, The Ohio Oil Co., of Guatemala, Guatemela City; O. W. Ward, Tennessee Gas & Oil Co., Calgary, and Raul N. Vigilone, Y.P.F., Buenos Aires.

PESA Sets Two Dates For Meetings in Spring

Dates have been set for two of the five Petroleum Equipment Suppliers Association district membership meetings to be held in the Spring.

Chairman Elliott A. Johnson of the Gulf Coast District has selected Thursday, April 14, 1960, as the date for the meeting in that district, and Chairman H. H. Peters has selected Tuesday, April 26, as the date for the Pacific District Meeting. Locations for the meetings have not been disclosed.

Rocky Mountain Group Elects Gower President

Frank H. Gower of Denver was elected president of the Rocky Mountain Oil and Gas Association at its fourteenth annual convention.

Gower, an independent oil operator, succeeds A. F. Barrett of Billings, Mont.

API Committee Chairmanship Assumed by C. W. Dawson

C. W. Dawson, associate chief engineer of Standard Oil Co. of California, San Francisco, has assumed the chairmanship of the Committee on Standardization of Tubular Goods of the API's Division of Production. He succeeds C. A. Dunlop of Humble Oil & Refining Co., who has retired.

Dawson has announced that Paul Thomas, Asiatic Petroleum Co., New York, has succeeded him as chairman of the User Subcommittee on Casing, Tubing and Drill Pipe, and that C. E. Rawlings, Phillips Petroleum Co., Bartlesville, Okla., has succeeded Thomas as chairman of the Subcommittee on Pipe Research.

J. E. Walters Wins First Prize at GCAGS Convention

John E. Walters, Texas Division geologist for Michel T. Halbouty, was awarded first prize for his presentation of the paper making the most important contribution to the knowledge of petroleum geology in the Gulf Coast Region at the ninth annual convention of the Gulf Coast Association of Geological Societies.

J. E. Walters

Walters' paper was titled "Effect of Structural Movement on Sedimentation in the Pheasant-Francitas Area, Matagorda and Jackson Counties, Texas." The award included a parchment scroll and a cash prize of $300.

Ramsey L. Oakes, independent geologist from New Orleans, was awarded $200 as second prize winner for his paper "The Grandison Complex, Lafourche and Jefferson Parishes, Louisiana."

Hugh A. Bernard, C. Fred Major, and

Los Angeles NOMADS

International guests who attended a recent meeting of the Los Angeles Chapter of NOMADS are: Left to right: (standing) Eberhard Witte of Fargo GMBH from Germany; C. L. Buckingham of Camdrill from Algeria; Patrick L. Dobey of Mobil Oil from Libya; C. M. Williams of L.T.S. from Algeria; Amir H. Amiri of NIOC from Iran; John Donovan of IPC from Iraq; Ray P. Sprague of Drillexco from Libya; and Voyd H. Clark of Aramco from Saudi Arabia. (Seated) Wm. H. Anderson of Petrobras from Brazil; Jack Wilkinson of IPC from Iraq; Dick Daugherty, ex-Rams football player, speaker; Don Cox of IPC from Iraq; and Roy E. McNeil of Drilling Exploration from Nigeria.

B. S. Parrott, geologists with the Shell Development Company, Houston, were awarded third prize of $100 for their paper "The Galveston Barrier Island and Environs."

Geological Society Elects Dr. H. D. Hedberg President

Dr. Hollis D. Hedberg, vice president, exploration, Gulf Oil Corporation, was elected president of the Geological Society of America at the annual meeting recently in Pittsburgh.

Dr. H. D. Hedberg

Thomas B. Nolan of the United States Geological Survey, Washington, D.C., was elected vice president. The following were elected councilors: Harold L. James, also of the U.S.G.S.; Vincent C. Kelley, University of New Mexico; George D. Wollard, University of Wisconsin, and Norman D. Newell, Columbia University.

New Officers Elected for Fort Smith Geological Society

The Fort Smith Geological Society has elected new officers for 1959-60. They are B. W. Miller, Gulf Oil Corporation, president; Floyd W. Mock, Arkansas Louisiana Gas Company, vice president; and Roger N. Planalp, Athletic M & S Company, secretary-treasurer. The society is affiliated with the AAPG.

Oklahoma AAODC Chapter Elects Officers for 1960

L. Glenn Moore, Vierson & Cochran, Oklahoma City, has been elected chairman of the Central Oklahoma Chapter of the American Association of Oilwell Drilling Contractors for 1960. Other officers include Gene Bowman, Big Chief Drilling Company, Oklahoma City, vice chairman-program; Alvin S. Nuckolls, Nuckolls-Bell Drilling Company, Okla-

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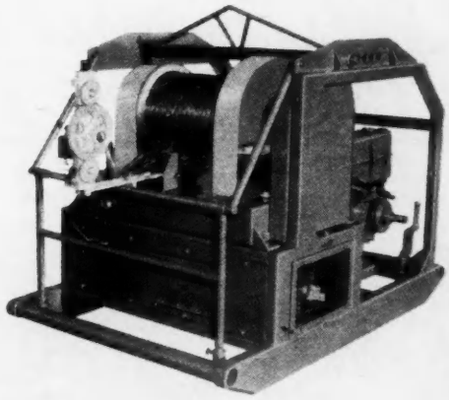

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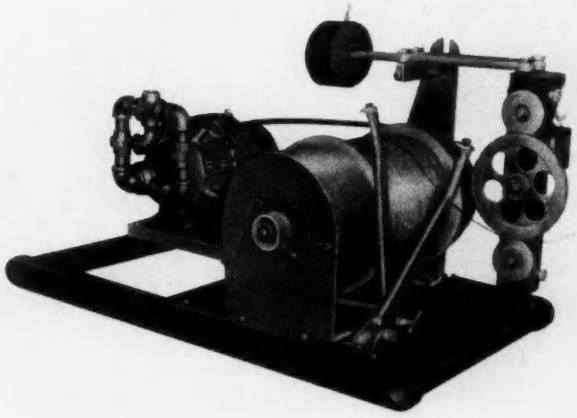

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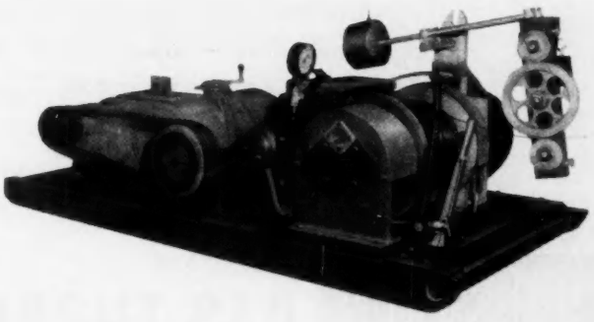

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Associations

homa City, vice chairman-memberships; Fred McCowan, T. T. Eason & Company, Oklahoma City, secretary, and B. D. McCampbell, An-Son Drilling Company, Oklahoma City, treasurer.

California Chapter of API Honors Russell B. Hodgson

Russell B. Hodgson, joint Ventura representative for Tidewater Oil Company's Western Division Production Department, has been given the meritorious service award of the California Coastal Chapter, API, Division of Production.

The award acknowledges Hodgson's "distinguished and meritorious service" in providing constructive leadership in the formation and program of the chapter.

Norman Knapp New President Of N.D. Geological Society

Norman Knapp, Mobil Producing Co., Billings, Mont., has been elected president of the North Dakota Geological Society.

Other officers include Howard L. Ellinwood, The California Co., Bismarck, vice president; Howard Armentrout, Calvert Drilling Co., Billings, treasurer; and William R. Bolenbaugh, Texaco Inc., Casper, Wyo., secretary.

Campbell Named Chairman Of Kansas AAODC Chapter

Robert C. Campbell of Sierra Petroleum Co. was elected chairman of the Kansas Chapter of the American Association of Oilwell Contractors. Campbell succeeds Emmett Hall, Gabbert-Jones Drilling Co., who has become chairman of the executive committee.

Other officers for 1960 are Fred Barker, with Earl F. Wakefield, and A. L. Rhodes, Sterling Drilling Co., both vice presidents. Lorin Baker, Rine Drilling Co., is secretary-treasurer.

International Oil Scouts Complete 29th Year Book

William P. Allen, scout for the Imperial Oil Ltd., Calgary, Alta., and president of the National Oil Scouts and Landmen's Association, has announced the completion of the Association's Twenty-Ninth Yearbook, *Oil and Gas Field Development.*

The Yearbook contains 1,136 pages and reviews oil and gas activity during 1958 in 34 states, including Alaska and all of Canada.

ERRATUM

The posted nuclear log on Page 100 of the December 1959 issue of WORLD OIL (Central Kentucky Activity to Reach Record Heights) erroneously labeled the Laurel dolomite as "Laurel shale." As stated in the article, the Laurel is a dolomite throughout most of central Kentucky and in parts of northern Tennessee where it is found on the surface and in the subsurface.

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ESTIMATOR'S PIPING MAN HOUR MANUAL, Gulf Publishing Company, P. O. Box 2608, Houston 1, Texas, by John S. Page and Jim G. Nation, Price $7.50

The authors, estimators by profession, have found after much comparison on many projects that production percentages can be classified into five categories, namely: very low, low, average, very good and excellent. And, that production elements can be grouped into six different listings or categories which are: general economy, project supervision, labor relations, job conditions, equipment and weather.

Using the above experience, the authors have devised an accurate and convenient method of estimating direct labor for complete fabrication and installation of process piping for any given system. Thus, by means of this manual, the reader has a method of obtaining a production efficiency percentage by applying all known local conditions and variables . . . plus a method of obtaining a complete direct labor rate for the craft or crafts involved in the various operations.

Subject areas covered include: shop fabrication of pipe and fittings, field fabrication and erection, alloy and non-ferrous fabrication, underground piping, hangers and supports, painting, patent scaffolding, insulation. To enable the reader to get more from the manual, the authors have provided a comprehensive sample estimate. Also, there is a section devoted to technical information which will be of benefit to the reader in preparing an estimate.

The manual may be purchased from the Book Department of Gulf Publishing Co.

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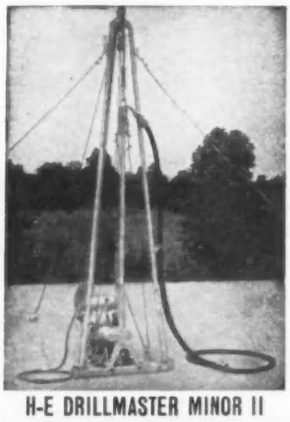

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THE AMERICAN PETROLEUM INDUSTRY 1859-1899, The Age of Illumination, Northwestern University Press, Evanston, Ill., Harold F. Williamson and Arnold R. Daum.

This work traces the growth of the American petroleum industry from 1859, when Edwin L. Drake drilled the first commercially successful oil well in the United States at Titusville, Penn., until the end of the nineteenth century, when the age of kerosine illumination ended and the gasoline age began.

The Age of Illumination, the first of a definite two-volume history, is based on years of intensive research sponsored by the American Petroleum Institute, into original source material.

The general reader will learn of the incidents that explain the close relationship between the efforts of the oil industry to expand its markets and the effect on living standards both at home and abroad.

All readers will appreciate the inclusion of nearly 150 maps, diagrams and photographs that illustrate the various developments within the industry and depict the leading personalities connected with its history.

PROCEEDINGS OF THE SYMPOSIUM ON THE DEVELOPMENT OF PETROLEUM RESOURCES OF ASIA AND THE FAR EAST, Mineral Resources Development Series No. 10, United Nations Economic Commission for Asia and the Far East, United Nations Publication, $2.50 (U.S.); 18/- sterling; Swiss France 10.50 (or equivalent in other currencies).

This publication contains the report and the principal documents of the Symposium on the Development of Petroleum Resources of Asia and the Far East, which was held in New Delhi, India, from December 3 to 16, 1958, under the sponsorship of the United Nations Economic Commission for Asia and the Far East (ECAFE).

It consists of two parts; Part I, Report of the Symposium and Part II, Documentation. Part II is further divided into A. Documents of general scope; B. Documents pertaining to the ECAFE region as a whole; C. Documents relating to petroleum resources in countries of the ECAFE region; D. Documents relating to petroleum resources, development in countries of the ECAFE region; and E. Documents concerning regulations governing petroleum resources development. Maps for the documents are under preparation, and will be issued separately as annex to this publication.

WHO'S MEETING WHERE

Jan. 4–15	Advanced Drilling Engineering Course, Texas A. & M. College, College Station, Texas.
11–13	First International Symposium on Arctic Geology, Jubilee Auditorium, Calgary, Alberta.
11–15	SAE, Annual Meeting, Sheraton-Cadillac Hotel, Detroit.
15–16	International Oil Scouts Association, Directors Meeting, Adolphus Hotel, Dallas.
17–19	Kansas Oil Men's Association 45th Annual Convention, Broadview Hotel, Wichita, Kan.
20	Oil Trades Association of New York Meeting, Waldorf-Astoria Hotel, New York City.
28–29	Houston Section NACE, Two Day Course in Practical Corrosion Control Systems for Oil & Gas Production, Rice Hotel, Houston.
29–30	Fluids in Rocks Conference, University of California, Los Angeles.
Feb. 8–10	AAPG, Rocky Mountain Section, Tenth Annual Meeting, Billings, Mont.
14–18	AIME, Annual Meeting, Statler Hotel, New York City.
Mar. 2– 4	API, Division of Production, Southwestern District Meeting, Statler-Hilton Hotel, Dallas.
14–18	NACE, 16th Annual Meeting, Memorial Auditorium, Dallas.
16–18	API, Division of Production, Southern District Meeting, Hilton Hotel, San Antonio, Texas.
23	Oil Trade Association of New York Meeting, Waldorf-Astoria Hotel, New York City.
30 thru Apr. 1	API, Division of Production, Mid-Continent District Meeting, Broadview Hotel, Wichita, Kan.
April 20–22	API, Division of Production, Rocky Mountain District Meeting, Gladstone, Henning and Townsend hotels, Casper, Wyo.
20–22	NPA, Semi-annual Meeting, Hotel Cleveland, Cleveland.
21–23	Permian Basin Section SEPM, Annual Meeting and Field Trip, Abilene, Texas.
24–26	IPA of America, Mid-Year Meeting, Denver-Hilton Hotel, Denver.
25–28	AAPG-SEPM, Annual Meeting, Chalfonte-Haddon Hall, Atlantic City, N.J.
25– thru May 6	Advanced Drilling Engineering Course, Texas A. & M. College, College Station, Texas.
May 1– 4	API, Division of Transportation, Tanker Conference, Seaview Country Club, Absecon, N.J.
2– 3	SAE of AIME, Wichita Falls, Texas.
2– 4	AIME, North Texas Secondary Recovery Symposium (Biennial), Wichita Falls, Texas.
5– 6	AIME, Rocky Mountain Petroleum Sections, Annual Joint Meeting, Calgary, Alb., Canada.
12–13	API Division of Production, Pacific Coast District Meeting, Biltmore Hotel, Los Angeles.
25–28	AAPG, Western Canada Reginal Meeting, Banff Springs Hotel, Banff, Alberta.
June 5–10	SAE, Summer Meeting, Edgewater Beach Hotel, Chicago.
12–17	API Division of Production, Mid-year Committee Conference, Sheraton-Dallas Hotel, Dallas.
28–30	API Division of Production, Eastern District Meeting, Greenbriar Hotel, White Sulphur Springs, W. Va.

Nomads' Chapter monthly meeting: Los Angeles, second Wednesday, Hotel Biltmore, Wallace A. Sawdon, Secretary. Houston, second Monday, Ye Old College Inn, Harry E. Estes, Secretary. Dallas-Fort Worth, first Monday, Greater Dallas Club, Hank Davis, Secretary. Tulsa, Hotel Tulsa, Gilbert Swift, Secretary. New York, first Monday, Hotel Biltmore, Jesse E. Hickman, Secretary.

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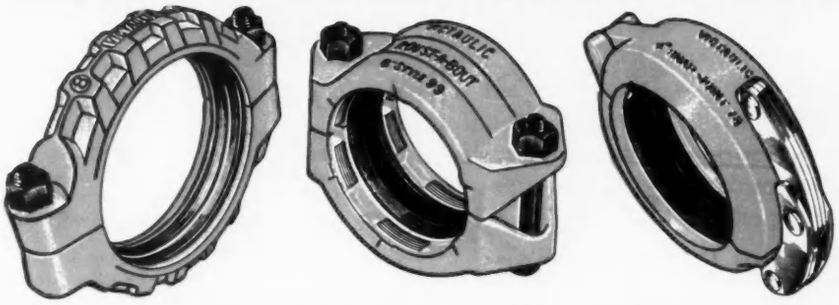

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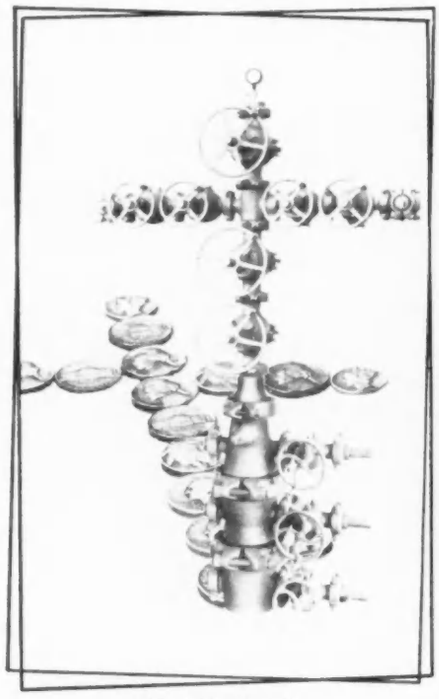

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REpublic 4-1641 5909

Suppliers' notes

Byron Jackson Emphasizes Product Development

New product development was the theme of a national meeting of Byron Jackson Oil Tool, Inc., held recently in Houston. Keynote of the meeting was the company's expanded new product research and development program. The three day conclave was attended by upper management executives and divisional and regional sales managers from all parts of the United States. First row (left to right): Don Appleford, T. W. Jurling, Harold C. Starr, Vern W. Hillyard, John P. Kirby and A. R. Boyd. Second row: W. C. Brooks, O. J. File, A. W. Rose, president, R. J. Evans, Jr., vice president and domestic sales manager who directed the meeting, I. B. Bryan, P. A. Jordan and G. F. Nicolson, vice president and assistant general manager. Third row: R. E. Leasure, J. S. Smith, R. G. Taylor, Jr., manager of engineering, R. T. Todd, W. F. Roberts, Jr., Si Tamny and John C. Grant, chief engineer, P. B. Rubber Products. Present at the meeting but not shown in the picture was John O. Ramsey, advertising consultant.

Ralph Hickey

Morris Varnadore

Ralph Hickey and Morris Varnadore have been appointed sales representatives for **Southwestern Pipe, Inc.,** to expand field services in West Texas, New Mexico, Oklahoma and Kansas. Hickey has set up offices in Tulsa in the Enterprise Building and will cover Oklahoma and Kansas for Southwestern's Lightwall electric resistance-weld line pipe. Varnadore has been located in the Midland Savings & Loan Building, Midland, Texas. He will serve West Texas and New Mexico.

H. D. (Dave) Collins has been appointed manager of the Chicago South Side branch of **White Truck Division** of **The White Motor Company.** The Chicago North Side branch for White is managed by **Clarence Hagstrom.**

J. W. Lowrance, Jr., has been appointed production valve salesman representative for **Grove Valve and Regulator Company** in the Rocky Mountain region.

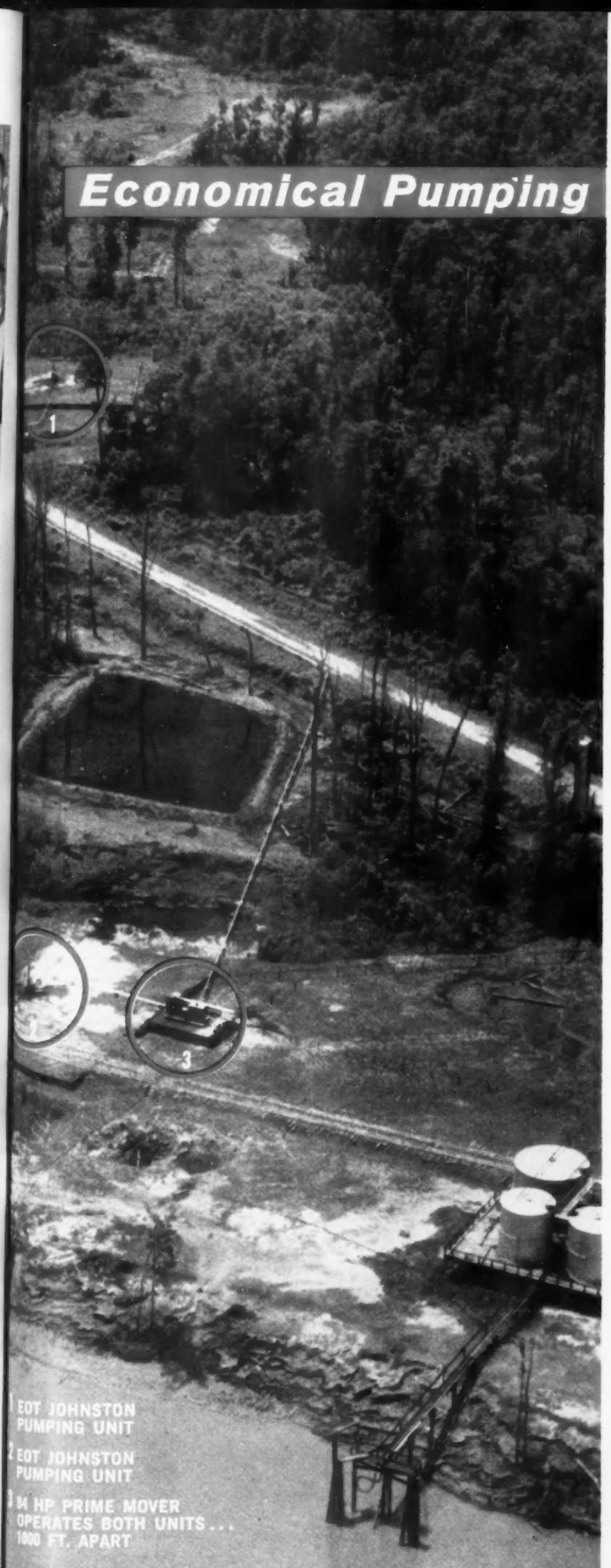
W. D. Raymond, assistant controller, **Dresser Industries, Inc.,** Dallas; **L. W. Stanberry,** secretary-treasurer, **W. C. Norris, Manufacturer, Division of Dover Corporation,** Tulsa; **C. B. Chantler,** controller, and **Martin McKee,** assistant comptroller, both of **Standard Oil Company of California, Western Operation, Inc.,** San Francisco, have all been elected to membership in the **Controllers Institute of America.**

Fenton M. Wood has been made vice president in charge of research and development of the **Tuboscope Company,** Houston. Prior to his promotion, Wood was chief design engineer.

George E. Conner has been elected president of **Milwhite Mud Sales Company** of Houston. Conner joined Milwhite in 1954 as a salesman. In 1955 he was promoted to sales manager, and in 1958 was elected to serve as executive vice president of Milwhite. Also, **Geo. W. (Bill) Bowman** has joined the Milwhite staff as a sales representative in the Fort Worth area.

G. E. Conner

J. D. McCall has been appointed president of **Columbia-Geneva Steel Corporation,** with headquarters in San Francisco. McCall succeeds **Leslie B. Worthington,** who was formerly president



Economical Pumping ... ONE POWER UNIT OPERATES TWO

EOT

JOHNSTON

Hydraulic

PUMPING UNITS

The EOT-Johnston Hydraulic Pumping Unit is the economical way to produce wells. Initial cost is less . . . installation cost is less than conventional beam-type units . . . and, as you can see from the field installation photo on the left, the power source is economical, too.

From Mexico to Canada, California to West Virginia, operators have field-tested the EOT unit. This ruggedly constructed pumping unit requires a minimum of maintenance, and in remote, inaccessible areas this is the pumping unit operators prefer because of its dependable performance. Compare cost or performance. The EOT-Johnston unit measures up!

Before you buy your next pumping unit, get all the facts and figures. Compare the initial cost, operating cost and proven performance of the EOT-Johnston pumping unit against conventional beam-type units. You will see why profit-minded operators specify EOT-Johnston Hydraulic Pumping Units when their wells go on artificial lift.

Aerial photo (left) shows the Sohio Petroleum Co.'s EOT-Johnston pump installations. Located on the banks of the Atchafalaya River in the St. Martin Parish, La.; the two units are driven by one 84 h.p. prime mover using gas from the wellhead. The two pumping units are 1000 feet apart in this remote location.

EOT

ENGINEERED OIL TOOLS, INC.

1710 BURNETT ST. HOUSTON, TEXAS
P. O. BOX 1665 PHONE FA 3-0293

DISTRIBUTORS

DOMESTIC: Bovaird Supply Co.; Lacy Oil Tool Co.; McJunkin Corp.; Production Equipment Products Co.; Union Supply Co.; Wilson Supply Co. CANADA: Canadian Well Services, Ltd. EXPORT: Wilson Supply Co., International Div.

5912

A man who's out to make a name for himself and his company – makes it a habit to read his businesspaper regularly and thoroughly. You know there's no surer way to keep abreast of what goes on in your trade or industry. No richer source of useful, usable ideas for getting ahead in your job, or in your field –than the advertising and editorial pages of... your businesspaper.

PHOTO ON LOCATION BY EHRENBERG

Where there's business action, there's a businesspaper . . . where there's drilling-production business there's **WORLD OIL**

One of a series of advertisements prepared by the ASSOCIATED BUSINESS PUBLICATIONS

Suppliers' notes

of Columbia-Geneva, and is now president of **U.S. Steel Corporation.** Worthington was elected president of U.S. Steel last November.

Dan Fagan has been transferred from Odessa, Texas, to Pampa, Texas, by **Gulf Coast Machine & Supply Company.** A native of Pampa, Fagan returns to his home after several years in sales and service in West Texas and New Mexico.

Thomas H. Mullen has been named director of Customer Relations of the USI Technical Center in Pompano Beach, Florida, research and development division of **U.S. Industries, Inc.**

W. M. (Bill) Hiddleston has resigned from the George E. Failing Company, Enid, Okla., to become sales manager for **Logmaster Services, Inc.,** at Enid.

Robert B. Gibbs has been transferred from Odessa, Texas, to **Lufkin Foundry and Machine Company's** export office in New York City. Gibbs has been a sales engineer for Lufkin at Odessa since 1953. He will assist **A. V. Simonson,** export division manager, in the sale of Lufkin equipment outside the United States.

R. B. Gibbs

E. E. (Dusty) Rhodes, Tulsa, has been appointed sales and service representative for the state of Oklahoma by **Oil Metering and Processing Equipment Corporation** of Houston.

W. W. Gratehouse has been named vice president of **Drilling Tools, Inc.,** and **J. E. Pattillo, Jr.,** has been promoted to sales manager of the company.

H. J. Soileau has been promoted to store manager at **Jones & Laughlin Supply Division's** Harvey, La., store. Soileau joined Jones & Laughlin at the Harvey store in 1954 and was later transferred to the Houma, La., store.

Rex W. Landry has joined **Daniel Orifice Fitting Company** as application engineer in charge of meter station design.

Daniel Lee Nicholson has been named production valve salesman by **Grove Valve and Regulator Co.** in the Oklahoma area. Nicholson will handle sales of Grove production valves in Oklahoma and parts of Southern Kansas. He will headquarter in Oklahoma City.

E. B. Speer, presently vice president-operations-steel, **United States Steel Corporation,** has been appointed administrative vice president-central operations (steel and coal), succeeding **Edwin H. Gott** who was recently named executive vice president-production.

another
TRETOLITE SERVICE
report

SOLVO*PARAFFIN REMOVER REDUCES FLOW LINE PRESSURE from 430 to 20 psig

When SOLVO Paraffin Remover treatment was started on a Kansas well, the flow line pressure was at 430 p.s.i.g. Within 48 hours the flow line pressure dropped to 100 p.s.i.g. and at the end of five days' SOLVO treatment, the flow line was operating at its normal pressure of 20 p.s.i.g. The table shows how SOLVO Paraffin Remover was applied.

TIME LAPSE	AMOUNT OF SOLVO USED	WHERE SOLVO WAS APPLIED	FLOW LINE PRESSURE (p.s.i.g.)
Start	5 gals. SOLVO 5 gals. Kerosine	Well Annulus	430
24 hrs.	5 gals. SOLVO	Flow Line	430
48 hrs.	2 gals. SOLVO 1 qt. Moth Balls	Flow Line	100
72 hrs.	0	—	20

An important consideration in this case is the fact that the flow line pressure had built up to the 430 p.s.i.g. with a so-called "paraffin solvent" in use. This paraffin solvent cost the producer 20% more per gallon than SOLVO.

P.S.: SOLVO Paraffin Remover was applied to *all* wells on this lease. The reduced flow line pressures in every case showed effective paraffin removal. The improved SOLVO treatment resulted in a savings in chemical costs of $100.00 per month.

SOLVO PARAFFIN REMOVERS CONTAIN NO CHLORINATED SOLVENTS

For complete information, *ask the Man in the Red Car.*

*SOLVO *is a registered trademark of Petrolite Corporation.*

PR-59-2

PETROLITE
CORPORATION

TRETOLITE COMPANY
DIVISIONS
369 Marshall Avenue, Saint Louis 19, Missouri
5515 Telegraph Road, Los Angeles 22, California

CANADA: Petrolite Corporation of Canada, Limited, 309 Alexandra Bldg., Edmonton, Alberta

ENGLAND: Petrolite Limited, Heathcoat House, 20, Savile Row, London W. 1.

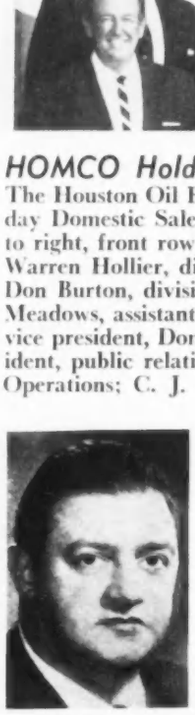
VENEZUELA: South American Petrolite Corporation, Hotel Avila, Caracas

REPRESENTATIVES

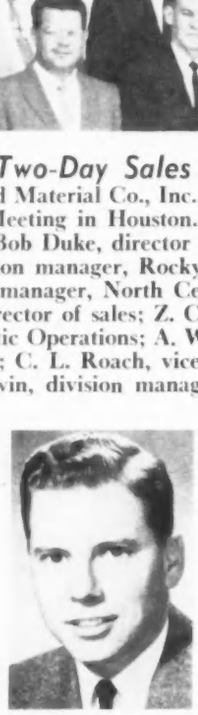
BRAZIL: WERCO, Ltda., Avenida Rio Branco 57-s/1410-11, Rio de Janeiro
COLOMBIA: W. F. Faulkner, Calle 19, No. 7-30, Office 807, Bogota
GERMANY: H. Costenoble, Guiollettstrasse 47, Frankfort, a.M.
ITALY: NYMCO S.p.A. 9, Lungotevere A. da Brescia, Rome
JAPAN: Maruwa Bussan KK, No. 3, 2-Chome, Kyobashi, Chuo-Ku, Tokyo
KUWAIT: F. N. Dahdah, Box 1713, Al Kuwait
MEXICO: R. E. Power, Sierra de Mijes, No. 125, Mexico, D. F.
NETHERLANDS: F. E. C. Jenkins, Hoefbladlaan 134, The Hague
PERU: International Gas Lift Company, Apartado 71, Talara
TRINIDAD: Neal and Massy, Ltd., P.O. Box 544, Port of Spain

HOMCO Holds Two-Day Sales Meeting

The Houston Oil Field Material Co., Inc., recently held a two-day Domestic Sales Meeting in Houston. Attended were (left to right, front row): Bob Duke, director of Market Research; Warren Hollier, division manager, Rocky Mountain Division; Don Burton, division manager, North Central Division; Otho Meadows, assistant director of sales; Z. C. Ambrose, executive vice president, Domestic Operations; A. W. Waddill, vice president, public relations; C. L. Roach, vice president, Domestic Operations; C. J. Erwin, division manager, West Texas-New Mexico Division; R. M. Freeman, division manager, South Texas Division; L. H. Galeener, director of directional drilling. Back row (left to right): Roger Eason, director Oil Field Rentals; E. C. Alford, division manager, Eastern Louisiana Division; Gene Webb, division manager, Western Louisiana-Mississippi Division; T. C. Smith, director of Fishing-Cutting; H. H. Hughes, assistant director of Fishing-Cutting; Bob Dilworth, director of Sales; Howard Ward, division manager, California Division; Frank Singletary, assistant director of Directional Drilling; T. C. Burke, director of Supply.



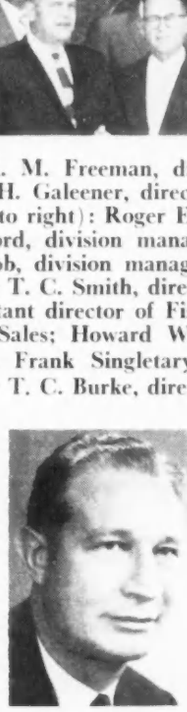
D. W. Sheehan



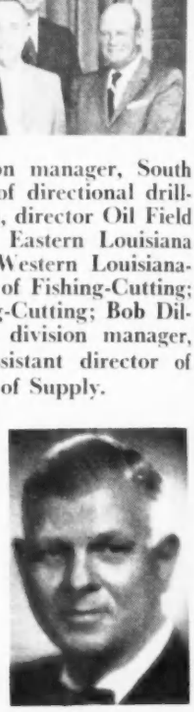
H. W. Haldeman

David W. Sheehan and **Harold W. Haldeman** have been appointed territory managers in the North Atlantic states by **White Truck Division** of **The White Motor Company.** Sheehan takes charge of distributor locations in metropolitan New York and northern New Jersey. Haldeman will head outlets in Connecticut, Maine, Massachusetts and Rhode Island.

Charles J. Spiker has been appointed manager, oil field accounting, by **The National Supply Company.**

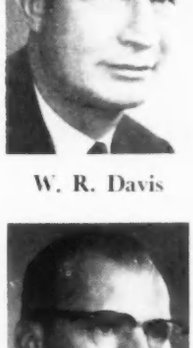


W. R. Davis

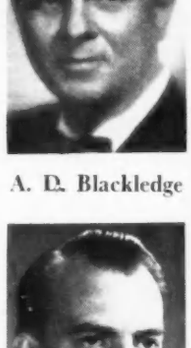


A. D. Blackledge

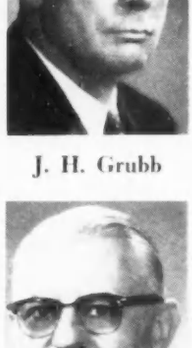
WHEELING
COUPLINGS
FOR OIL COUNTRY USE
LINE PIPE COUPLINGS A. P. I.
1/8" to 12"—Seamless, Black or Galvanized
PLAIN TUBING COUPLINGS A. P. I.
1" to 4"—Seamless
EXTERNAL UPSET TUBING COUPLINGS A. P. I.
3/4" to 3 1/2"—Seamless
CASING COUPLINGS A. P. I.
4 1/2" to 13 3/8"—Long or Short
HYDRAULIC COUPLINGS
1/8" to 4"—Seamless
REAMED AND DRIFTED A. I. S. I.
3/4" to 12"—Seamless
DRIVE PIPE COUPLINGS
6" to 12"—Seamless
PIPE NIPPLES
All Sizes and Types
STEEL BUSHINGS AND PLUGS
Merchant and High Pressure
WHEELING MACHINE PRODUCTS COMPANY
WHEELING, WEST VIRGINIA
WEST COAST FACTORY: WOODLAKE, CALIFORNIA



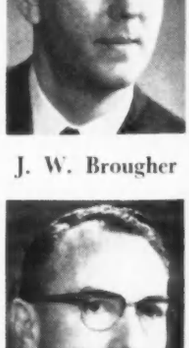
J. H. Grubb



J. W. Brougher



C. G. Hayward



J. B. Ogden

Cameron Names Six New Vice Presidents

The directors of Cameron Iron Works, Inc., Houston, have elected six new vice presidents.

They are: A. D. Blackledge, with Cameron for the past 10 years, was elected vice president and assistant manager; W. R. Davis, with Cameron for 19 years, was named vice president

Suppliers' notes

and manager of the Pressure Control Equipment Division; J. H. Grubb, with Cameron since 1955, was named vice president and manager of the International Division; J. W. Brougher, with Cameron for five years, was elected vice president and manager of the Special Products Division; C. G. Hayward, with Cameron for eight years, was named vice president and controller; and J. B. Ogden, serving in the Industrial Relations Department for 18 years, was elected vice president and manager of industrial relations.

J. S. Abercrombie is president and board chairman. Other officers of the company who were re-elected include R. H. McCullough, secretary-treasurer, and Herbert Allen, vice president and general manager.

Woodfield Pickering Limited Serving European Market

Woodfield Pickering Limited has recently been formed in Europe through the combining of R. Y. Pickering & Co., Ltd., one of The Lithgow Group of Companies, of Wishaw, Lanarkshire, and Woodfield Rochester, Ltd. The pooling of Scottish and English industrial interests which include heavy and light engineering, shipbuilding, hydraulics, electronics and manufacture of oil drilling equipment will provide a new all-in service for oil companies contemplating off-shore continental shelf drilling. According to the company, one advantage offered by the new firm is that equipment bought by oil companies will have a shorter tow to the Middle East.

Stardrill-Keystone Integrated With Buffalo-Springfield Co.

Sales activities of Stardrill-Keystone Division, recently acquired by Koehring Co., Milwaukee, Wis., have been integrated with another Koehring division, Buffalo-Springfield Co., Springfield, Ohio. The new division will be known as Buffalo-Springfield Co. The Stardrill-Keystone Division name will be retained.

Due to the integration of the two divisions, the following appointments were made: Howard D. Barnhart was appointed domestic sales manager, Stardrill-Keystone products. Barnhart was formerly manager of Stardrill-Keystone. H. J. Allen to vice president, export sales, for Stardrill-Keystone products. Glenn E. Moore to product manager reporting to R. E. Burton, president of Buffalo-Springfield. Moore will act as liaison among Buffalo-Springfield Co., Stardrill-Keystone and the Franks Machine Co. Ned E. Girlando to senior drill project engineer for the Buffalo-Springfield Co., reporting to the chief engineer. Robert Troy to assistant domestic sales manager for Stardrill-Keystone products reporting to the domestic sales manager. R. C. Johnston to assistant export sales manager reporting to Allen. Thomas M. Greene to assistant works manager reporting to W. H. Mathys, works manager. Richard Kemmerly to production manager, Buffalo-Springfield Co. Kemmerly was formerly purchasing agent with Stardrill. L. Charles Siemon to purchasing agent with Buffalo. H. J. Ruttenburg, formerly president of Stardrill, will become a consultant with the firm.

Rochester Company Secures Large Yugoslav Contract

Woodfield Rochester Limited has been awarded a large contract for the manufacture of oil field drilling and production equipment by Yugoslavia. Notice of the contract in Yugoslavia being offered was given by Woodfield agents, Standard Representative Engineers of Belgrade.

The contract is for the manufacture and supply of a number of drilling rigs capable of drilling to depths of 8,500 feet, together with drilling equipment.

Several British companies will be associated with Woodfield as sub-contractors in the supply of equipment. They are: Failing Supplies Ltd.; Foamite Limited; J. K. Smit & Sons (Diamond Tools) Ltd.; Le Grand Rochester Limited; Oil Well Supply Company Limited; The National Supply Company Limited; and Transport Equipment (Thornycroft) Limited.

Fred E. Cooper Begins Plant Expansion in Tulsa

Fred E. Cooper, Inc., with home offices and main plant in Tulsa, has begun an extensive over-all plant expansion program at the plant site which is estimated to exceed $250,000.

General office space will be increased by 89 percent. The fabricating shop will be 95 percent larger and will be equipped with two heavy duty overhead electric cranes having a hook lift of 20 feet. The shop will be equipped with most modern shop and machine tools. Machinery overhaul space is being enlarged 100 percent. The additional repair space is being built in dimensions to take the largest Cooper machines with reserve room for possible additional increase in the size of the machinery.

WORLD OIL'S **Trading Post**

CLASSIFIED ADVERTISING

RATES: Regular Classified (undisplayed) **set in this size type: 20 cents per word. Minimum charge $4. Blind box address in our care counts six words. Replies forwarded without charge. Display Classified ads, set in suitably larger type with ruled border, $13.50 per column inch. Ten percent discount for two or more insertions of same copy in consecutive issues. All classified ads payable in advance.** Send copy and checks to: Trading Post Classified Section, World Oil. P. O. Box 2608, Houston, Texas.

HELP WANTED

SALESMAN WANTED

Well-established successful firm has opening in an expanding sales department for young man looking for an opportunity in sales work. Must be college graduate, not over 33, in good health, ambitious and not afraid of work. Oil industry experience desirable. The man we are looking for will be trained at home office before moving into sales work on basis of salary plus commission incentive and traveling expenses. Our own personnel know of this advertisement. Your reply will be confidential and should be sufficiently complete to merit contacting you for an interview. Address Box 200-W, WORLD OIL, Houston, Texas.

BUSINESS SERVICE

■ Financial Contacts, Underwriters, Private Brokers reached. No shopping. Confidential. Send details to Consultant—817 - 61st Street, Brooklyn, N. Y.

"Flowers for Thought"

SOUTHWEST FLORIST

Bank of The Southwest Bldg.

Houston, Texas

CA 5-6603

Cable Address:

SOUFLO, Houston, Texas

SITUATIONS WANTED

Former drilling contractor and oil producer that has recently sold out is interested in making contact with an individual, group or company to manage and supervise their oil and gas operations, domestic or foreign. Location immaterial. R. Makin, Box 1628, Petroleum Building, Hobbs, New Mexico.

■ Geologist-Geophysicist, 30, married, M.A. Geology. 1½ years domestic and 2 years foreign seismic exploration seeks position either foreign or domestic. Presently doing post-graduate work. Box 206-W, WORLD OIL, Houston, Texas.

FOR SALE

■ 100 Miles 10¾". 307 Wall Pipe. Used, in excellent condition. Immediate delivery. Plain end Machine cleaned, coated. Central Ohio Pipe Co., P. O. Box 5412, Shepherd sta. Columbus, Ohio 3. Phone C.L.36527.

■ BARGAIN PRICES on Army surplus parts for Failing 314 and Star 71. Transmissions, Rotary hose, V belts, rope sockets, boilers, pump liners and bearing. Truck chains 7:50 x 20 dual wt. 100 lbs. $10.00 pair. Quantity discount. J. Brooke Reed, Fredericktown, Ohio.

■ 3 Cable Tool Rigs for sale or lease. Drilling capacities 3500, 4000 and 4500 feet. Fully equipped, first-class shape. Call Mr. Burris, MU 2-2240, Midland.

for **leakproof, pressure-tight connections**

use **TiteSeal®**

SEALING COMPOUNDS

Heat and vibration-proof, non-solvent, will not shrink, crack or crumble. Makes all assemblies leak-proof and pressure-tight. Prevents rust, corrosion, joint seizure.

7 BASIC BLENDS

LIQUID WRENCH®

The super-penetrating rust solvent

LOOSENS rusted bolts, nuts, screws, 'frozen' parts

Liquid Wrench works *fast*...yet is absolutely safe for all metals and alloys.

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SOLDER SEAL

RADIATOR SPECIALTY CO.
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INCREASE PRODUCTION

CLEAN OUT CHOKING SAND

Excessive sand and sediment holds back your oil. For fast, easy clean out with fewer round trips and less down-time, use world famous Miller Sand Pumps.

SAND PUMP SIZES
O.D.—2½, 3, 3½, 4¼, 5, 5½, 7 in.
Lengths—20, 25, 30 ft.

Composite Catalog, Page 3400

Write for descriptive price list

MILLER SAND PUMPS

Miller Sand Pump Co.
General Offices, Box 4516
Oklahoma City 9, Okla

EXPORT OFFICES
30 Rockefeller Plaza
NEW YORK CITY 20, N. Y.

SQUEAKS

From the Bull Wheel

A Backward Student

"Dick is a lot smarter than I thought he was."

"What makes you say that?"

"Well, on our date, last night, I told him I would give him lessons in love and he said: "OK, let's start with the last lesson first."

Practical Nurse

One who falls in love with a wealthy patient.

The Honeymoon's Over

Wife (looking out the window): "It looks like rain."

Husband (eating breakfast): "Yeah, but that's all right Mabel, it smells a little like coffee anyway."

There Is a Limit

A wife went to court to ask for a divorce. She gave her age as 78 and her husband's age as 82. The judge asked how long she had been married.

"Sixty-two years," was the answer.

The judge expressed surprise. "Why do you want a divorce after being together so many years?" he queried.

"Well!" was the emphatic reply, "Enough is enough!"

Brave Boy, Junior

A couple of young boys walked into the dentist's office. One faced him boldly and said, "Doc, I want a tooth took out and I don't want no gas 'cause I'm in a hurry."

"I must say you're a brave boy," said the dentist, "which tooth is it?"

The little boy turned to his silent friend and said, "Show him your tooth, Albert."

Safety Statistics

What some people don't know about driving would fill a hospital.

A Dual Personality

"What happened to the girl you used to saw in half in your magic act?"

"She's living in Denver and Miami."

Help Me, Doc

"My wife," he told the psychiatrist, "has developed an inferiority complex. How can I keep her that way?"

WOODFIELD PIPE UNIONS

...give trouble-free service

- ★ *Field proved.*
- ★ *Pressures up to 10,000 p.s.i.; working pressure.*
- ★ *API Standard threads.*
- ★ *Forged Steel or Malleable Iron— Rigid, Misaligning and Ball Swivels.*
- ★ *Available anywhere.*

WOODFIELD ROCHESTER LTD.
Frindsbury Works · Rochester · England
Telephone: Strood 78421

IDECO WOODFIELD

Woodfield manufacture Ideco Oilfield Equipment

Slightly Below Par

First golfer: "I suppose you heard that poor old Tom killed his wife?"

Second golfer: "No! How?"

First golfer: "With a golf club."

Second golfer: "How many strokes?"

Now Hair This

A baldheaded barber was trying to sell his customer a bottle of hair tonic.

"How can you have the nerve to sell hair tonic when you yourself don't have a hair on your head?" asked the customer.

The barber shrugged, "So what, I have a friend who sells brassiers."

Down The Homestretch

While strolling through the woods, a young man was startled to see a nude girl race past him, closely followed by two men in white. A third man followed, carrying a heavy pail of sand.

"What's going on?" the young man asked.

"She's just escaped from the hospital," the man panted over his shoulder.

"OK," said the young man, "but why the sand?"

"Oh," puffed the sand-carrier, "I caught her yesterday. This is my handicap!"

To Be or Not To Be

Then there was the cub reporter who was assigned to cover the class play at the high school. He wrote: "The auditorium was filled with expectant mothers and fathers, eagerly awaiting the appearance of their offspring."

Gravel and Gertie

Two cement mixers ran off and got married. Now they have a little sidewalk running around the house.

Thanks No, Just Lunch

During the lunch-time rush crowd, many of the restaurant customers shared their tables with strangers. The very proper spinster selected a seat next to an attractive young office girl. The girl finished her sandwich and coffee, then settled back and lit up a cigarette. The older woman controlled herself for a few moments and then snapped, "I'd rather commit adultery than smoke in public." "So would I," said the girl, "but I only have an hour for lunch."

SECONDARY RECOVERY

PETROLEUM ENGINEERS
STEPHENS ENGINEERING
WICHITA FALLS, TEXAS

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Water Flooding Gas Repressuring
EVALUATION CORE ANALYSIS
SURVEYS ECONOMICS
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FIELD SUPERVISION
Phone 723-2167

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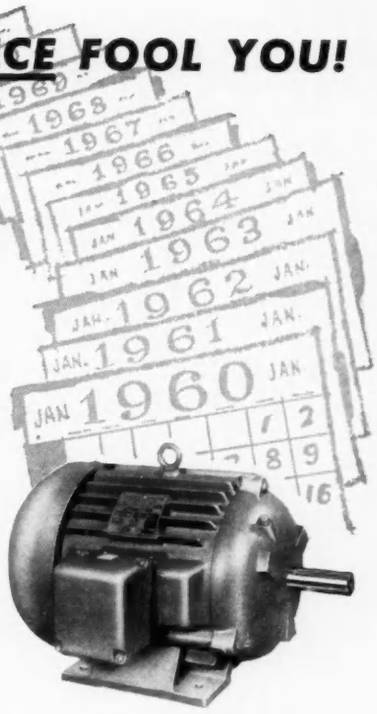
Despite Their Lower Cost

BROOK A.C. MOTORS

Give Outstanding Service



Anybody who knows motors will recognize that there is no finer motor than the Brook. These motors have established excellent service records in industry. Yet, they actually **cost less!**

Space age production methods and extensive distribution in 76 countries makes possible this better motor at lower cost. All standard enclosures. 1 to 600 H.P. Start saving now —look into Brook Motors at once. Write for literature and name of your dealer.

SINCE 1904
BROOK ELECTRIC MOTORS

world's most respected motor

BROOK MOTOR CORPORATION

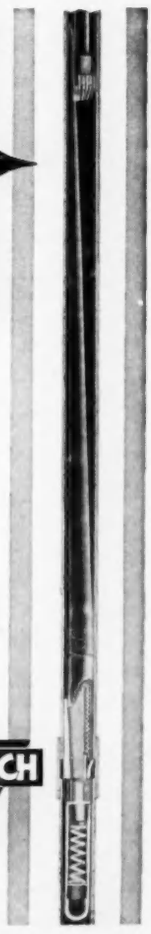
3302-04 W. Peterson Ave., Chicago 45, Ill.

Factory Representatives, Warehouses, Dealers, Service Stations, in Major Cities

In Canada: Brook Electric Motors of Canada Ltd., 250 University Ave., Toronto, Ont.

KINZBACH WHIPSTOCKS

POSITIVE SETTING... SAFE DRILL-OFF



You set your Kinzbach Whipstock at desired depth and position with absolute confidence of positive grip. Trigger assures that whipstock will be set so window will always be in only one joint of pipe. Concave section pivots on one direction hinge above slip section so upper lip always lies against pipe for safe passage of working tools; cannot be hinged into obstructing position.

Whipstock safely, where you want to, and in proper direction with Kinzbach Whipstocks. Available in all popular casing sizes.

KINZBACH TOOL CO INC

KINZBACH TOOL CO., INC.

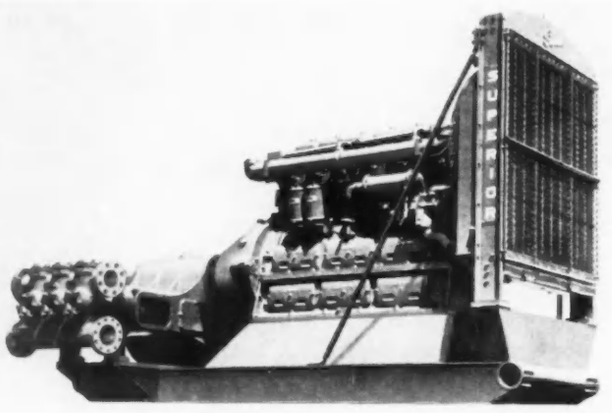
P. O. Box 277 • HOUSTON, TEXAS

EXPORT: 74 TRINITY PLACE, NEW YORK, N. Y.

NEW equipment and services

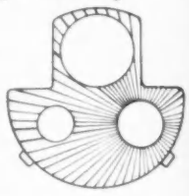
Engine-Pump Waterflood

A complete waterflood package—engine and pump with capacity up to 23,600 barrels per 24-hour day is now being marketed. Engine is a four-cycle, six-cylinder Superior G-510 that operates on natural gas or propane within the 190-400 BHP range. An improved combustion chamber with greater piston thrust provides high compression with marked fuel economy. (White Diesel Engine Division of The White Motor Company. Supplements data on Pages 2901-2920, 1958-1959 Composite Catalog.)

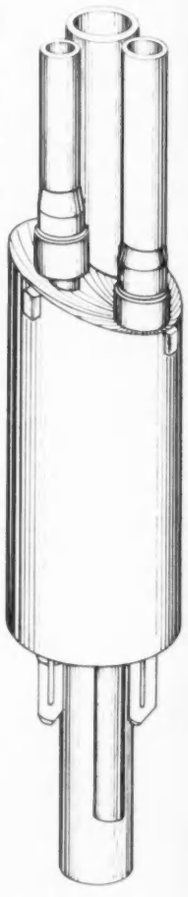


For more data, circle E1 on postcard

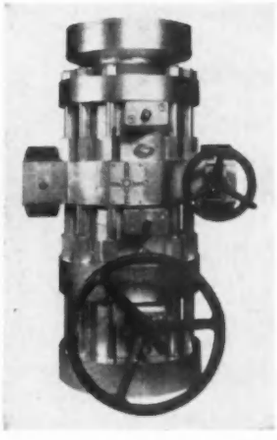
Hydraulic Pump Cavity



A closed power oil, parallel-free hydraulic pump cavity with stab-in-cross-over assembly has been developed. Run in on the 2½-inch tubing, the cavity permits 1¼-inch parallel tubing strings for power oil return and production return to be run individually and stabbed-in to seal off. Time saving of 30 to 50 percent is achieved over a simultaneous run-in of the conventional three strings. (Sargent Engineering Corp. Supplements data on Page 4423, 1958-1959 Composite Catalog).



For more data, circle E3 on postcard

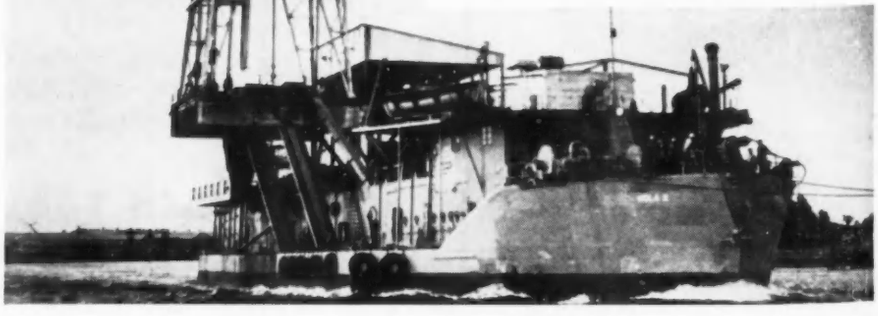


New Grove Valv-Pak

The Valv-Pak is a new breed of well head valve assembly which is less than half the size of conventional types. Available in any combination of master valves, wing valves, tees and bores tailored to meet individual needs. Bore sizes range from 1½ inches through 4. Working pressures from 2,000 to 10,000 pounds psi. Flange connections and bore seals can be supplied to meet any specification. (Grove Valve and Regulator Co. Supplements data on Pages 2125-2132, 1958-1959 Composite Catalog.)

For more data, circle E2 on postcard

New Offshore Derrick

A new type derrick designed for drilling from a floating vessel is composed of 16-welded sections with pin connections, rather than having individual members bolted together. Design reduces number of connections in structure to minimum, making it withstand rolling action of a floating vessel. Vertical track and roller device keeps traveling block from swinging. (Lee C. Moore and Zapata Off-Shore Company.)

For more data, circle E4 on postcard